INTERMOUNTAIN POWER SERVICE CORPORATION

April 4, 2001

Richard Sprott, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Dear Director Sprott,

NOTICE OF INTENT: Modification of Source

Intermountain Power Service Corporation (IPSC) is hereby submitting a Notice of Intent (NOI) to increase generating capacity at the Intermountain Generating Station (IGS) in Delta. The IGS is a coal fired steam-electric plant located in Millard County, a NAAQS Attainment Area. Specifically, IPSC intends to construct modifications to Units One and Two at IGS to enhance performance and reliability and to allow increased capacity by de-bottlenecking certain aspects of our operation. This NOI requests an approval order to construct and a revision to IPSC's Title V permit to incorporate these modifications.

As required by UAC R307-401-2, the following information is provided:

(1) PROCESS DESCRIPTION: IGS is a fossil-fuel fired steam-electric generating station that primarily uses coal as fuel for the production of steam to generate electricity (SIC Code 4911). Both bituminous and subbituminous coals are utilized. Fuel oil and used oil are also combusted for light off and energy recovery.

IGS is a two unit facility operating at a rated capacity of 875 megawatts (MW) per unit (gross). Approximately 5.3 million tons of coal and 600,000 gallons of oil (including used oil) are used each year in the production of electricity. Boiler capacity is rated at 6.2 million pounds per hour of steam flow at 2822 psi.

IGS has in place bulk handling equipment for the unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes of this equipment are proposed. No changes in the usage of other raw materials or bulk chemicals are planned.

850 West Brush Wellman Road, Delta, Utah 84624 Telephone [illegible] FAX [illegible]

PROPOSED CHANGES: IPSC is planning to enhance steam flow characteristics through the high pressure (HP) section of each turbine used to generate electricity. This involves the replacement of the HP section with a modified design that improves performance and reliability. This modification in and of itself will not increase plant capacity, but will instead lower emissions due to decreased fuel use from the resulting increased performance.

Combined improvements to other areas of the plant will increase plant generating capacity. These modifications consist of "de-bottlenecking" critical points that presently prevent the full utilization of present equipment. Other changes are needed for reliability, performance and/or routine maintenance purposes. See Item 8 for details.

(2) **EMISSION CHARACTERISTICS:** The composition and physical characteristics of the emissions are expected to change as a result of the proposed modifications as indicated in the attached spreadsheet (Attachment 1), which shows the anticipated changes in emission rates, temperature, air contaminant types, and concentration of air contaminants. The mass flow of chimney effluent may change proportionately with the fuel usage and combustion at a heat input comparable to the current heat input. The existing pollution control devices include low-NOx burners, fabric filters and wet scrubbers.

(3) **POLLUTION CONTROL DEVICE DESCRIPTION:** The existing pollution control device equipment includes dual register low NOx burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. The existing low NOx burners provide a nominal 60% reduction in potential combustion NOx formation, the baghouse filters operate at nominal 99.95% efficiency, and the wet scrubbers operate at nominal 90% efficiency. Control equipment for the handling and transfer of solid material include dust collection filters.

The project includes modifications to the flue gas flow through scrubber modules to enhance SO_2 and acid gas removal rates. Also, the project includes installation of moderately improved NOx controls, such as the replacement of the existing dual register low NOx burners with new technology staged combustion low NOx burners.

(4) **EMISSION POINT:** The present emission point for the IGS boilers is a lined chimney that discharges at 712 feet above ground level (5386 feet above sea level). The chimney location is 39° 39' 39" longitude, 112° 34' 46" latitude (UTM 4374448 meters Northing, 364239 meters Easting.).

(5) **SAMPLING/MONITORING:** Emissions from boiler combustion are continuously sampled and monitored at the chimney for nitrogen oxides, sulfur oxides, carbon dioxide, and volumetric flow. Opacity is measured at the fabric filter outlet. Other parameters recorded include heat input and production level (megawatt load). Monitoring will remain unchanged. Other emissions not directly monitored are calculated using engineering judgement, emission factors, and fuel analyses. The type and location of the monitors will not be changed.

(6) **OPERATING SCHEDULE:** IGS operates 24 hours per day, seven days per week. This will not change as a result of the proposed modifications.

(7) **CONSTRUCTION SCHEDULE:** Construction of the modifications will be performed in a staged manner, generally following the attached schedule. (See Attachment 2.)

(8) **MODIFICATION SPECIFICATIONS:** The changes covered by this NOI include:

- **High Pressure Turbine Retrofit:**

The high pressure turbine on each unit at IGS is scheduled to be replaced with a current technology, high efficiency turbine. This unit will increase high pressure turbine efficiency from approximately 84% to over 92%. Additionally, the turbine will be sized to provide up to 8.6% additional output.

- **Cooling Tower Performance Upgrade:**

The cooling towers on each unit at IGS are scheduled for performance enhancement modifications to increase heat rejection capacity. Also, cooling tower transformers feeding the cooling tower fan motors will be upgraded. A study will be performed to identify and resolve needed redundancy issues for operation at new output levels.

- **Boiler Safety Valve Additions:**
Currently, a review is underway focusing on existing boiler safety valve capacity. Addition of one main steam safety valve on each unit is expected in order to address reliability concerns with the existing valves and to accommodate planned increase in generation capacity.

- **Generator Cooling Enhancement:**
An engineering evaluation is currently underway to identify any enhancements required on the generator in order to accommodate the planned 8.6% increase in generator output. The anticipated result of this evaluation is an upgrade to the current generator and stator cooling systems.

- **Isophase Bus Cooling Enhancement:**
An engineering evaluation is currently underway to identify any enhancements required on the 26kv generator electrical bus feeding the main step-up transformer. The anticipated result of this evaluation is an upgrade to the current isophase bus duct cooling systems.

- **Large Motor Bus Loading Equalization:**
An engineering evaluation is currently underway to equalize the loading between the large and small motor bus. Due to limited tap adjustment capability on the auxiliary transformers feeding these load centers, several motors must be moved from one supply to the other in order to maintain required motor terminal voltages as unit output is increased.

- **Boiler Feed Pump Performance Upgrade:**
The boiler feed pump manufacturer has notified IPSC of several enhancements they now offer that address previous reliability concerns and allow for small increases in output. These include, improved bearing housings, flow path smoothing, and impeller clearance modifications. These modifications provide for increased pump output at acceptable reliability levels.

- **Main Step-up Transformer Cooling:**
The step-up transformer cores currently run close to their nominal temperature ratings when ambient temperatures are high. Proposed modifications are directed at increasing the cooling system capacity for cooling the transformer oil, core, and housing.

- **NOx Reduction Project:**
Some moderate NOx control systems will be added or enhanced. Recent advances in the burner industry have resulted in published operational data with improved NOx removal efficiencies. Within this project, burners in Unit 1 may be replaced with latest technology LNBs. Following successful testing, Unit 2 burner replacements would follow in successive outage upgrades. Alternatively, we may look at other technologies, or a combination of commercially available control systems. The installation of moderate NOx controls is expected to prevent any significant net increases of NOx due to increased capacity.

- **Scrubber Wall Ring:**
Scrubber wall ring technology has been developed and patented in recent years to address inefficient flow patterns that routinely develop within the absorber vessels. This ring would be installed within all twelve (12) scrubber absorber vessels to move flow back to the center of the vessel, providing more efficient SO_2 and acid gas scrubbing of the flue gas.

- **Generator Stator Cooling Water Oxygen Monitoring System:**
Given concerns in recent years regarding the long term integrity of the generator stator bars, an oxygen monitoring system, capable of early identification of stator bar degradation is essential. As load increases, stator bar temperature and cooling flow velocities are also expected to rise. This system will guard against unexpected degradation of the stator.

- **High Pressure Heater Drain Line Modifications:**
An existing resonant vibration occurring in the high pressure heater drain line to the deaerator has become an increasing concern. The vibration appears to increase with load. An increase in unit output would require a modification to eliminate this concern.

- **Boiler Modifications:**

A comprehensive study is currently underway with the manufacturer of the boilers (Babcock & Wilcox). This study has been designed to review all aspects of boiler operation at the new turbine output levels. This study includes evaluation of current technologies and operating practices for minimizing emissions. The study will provide recommendations for modifying the existing boilers for stable and efficient operation at the new higher rating.

- **Circulating Water Makeup Modifications:**

Current circulating water makeup capacity is inadequate for increased unit production. A new design will support increased makeup requirements and return a degree of redundancy to the system, as originally designed.

- **Boiler and turbine control system logic software & controls:**

Upgrade of the existing control system includes complete replacement of the plant information system, control system simulator, coordinated control system, turbine control systems, combustion control systems and the alarm indication system. The new control systems will eliminate parts availability and reliability issues as well as providing the increased control system capacity required for the projects associated with the increased unit output. Boiler and turbine operating parameters are controlled within closer tolerances, resulting in less upsets and better emission control.

The capital expenditures for these changes to both units is expected to be about $35 million. More detailed engineering specifications and project descriptions can be provided as needed.

PRODUCTION SUMMARY: The proposed project will increase generation capacity from 875 to approximately 950 MWhe, with steam flow design increasing from 6.2 to 6.9 million pounds per hour. Design heat input will increase from 8,352 to 9,225 million BTU per hour, requiring an increase from 5.3 to 5.6 million tons of coal each year. See Attachment 1 for details.

- **ADDITIONAL INFORMATION:** IGS operates under a Title V permit (#2700010001). IPSC intends to continue to operate in full compliance with that permit and applicable requirements. No deviations from permit conditions are expected. IPSC requests that this NOI also be considered a request for revision of the Title V permit, and requests that the conditions of the approval order be incorporated into the Title V permit once the approval order is issued.

Operating Flexibility

IPSC reserves the right to cancel any and all planned modifications at any time. IPSC may only install the turbine dense packs, which by themselves would not require review as a major modification. We note that EPA has previously determined that enhancements like the Dense Pack project are not major modifications if there is no significant net increase in emissions. (See letter from Francis X. Lyons, Regional Administrator, EPA Region 5 to Henry Nickel of Hunton & Williams, dated 5/23/00.) If IPSC decides to install only the Dense Pack enhancements and certain upgrades for reliability, IPSC will provide the supporting information to show that there will be no significant net increase in emissions.

Phased Permitting

Due to the length and intermittent nature of the construction schedule for the proposed modifications, IPSC requests that the approval order contain terms that take into account the phases of installation. For example, due to lead times for engineering and budgeting, some portions of the project which affect capacity and/or emissions may be installed prior to upgrades in pollution control equipment. IPSC would be receptive to an approval order that includes interim emission limits for the period prior to project completion and final upgrades to control equipment.

Permit "Off Ramps"

Budgeting for the proposed project will be considered on a fiscal year-by-year basis. Although the current business climate for increased capacity is very favorable for this project, outlooks may change. Accordingly, IPSC proposes that the approval order contain conditions which provide that pollution control upgrades will be required only if those "debottlenecking" projects go forward which, if installed without controls, would increase the potential to emit enough to require major modification review. If IPSC decides not to complete certain portions of this project, the approval order should be structured so that IPSC is not forced to proceed with project completion.

NSPS/PSD Applicability

New Source Performance Standards (NSPS). The proposed modifications do not trigger NSPS applicability under 40 CFR Part 60, Subpart Da. NSPS pollutants for this facility are NOx, SO_2 and PM10. A modification is defined for NSPS purposes to include any change in operation of a source that increases the maximum hourly emissions of a Part 60 regulated pollutant above the maximum achievable rate during the previous five years. See 40 CFR 60.14(h).

Prevention of Significant Deterioration. Planned upgrades to pollution control equipment as part of this proposed modification will result in net emissions decrease for certain criteria pollutants as a result of the project. Other pollutants may have increases below PSD significant levels. Accordingly, this modification will not require a major modification review. IPSC is providing to the DAQ supporting calculations and operating data.

Should you require any additional information, please contact Mr. Dennis Killian, Superintendent of Technical Services, at (435) 864-4414, or dennis-k@ipsc.com.

In as much as this notice of intent also constitutes a request for revision of IPSC's Title V Operating Permit, I hereby certify that, based on information and belief formed after reasonable inquiry, the statements and information in this document and the accompanying attachments are true, accurate, and complete.

Cordially,

S Gale Chapman

S. Gale Chapman
President, Chief Operations Officer, and Title V Responsible Official

Attachments: Excel Spreadsheets (Emissions)
Time Line Project Gantt Chart
IPSC Check, $1,200.00 NOI Fee

cc: Blaine Ipson, IPSC
Jerry Hintze, IPSC
Bruce Moore, LADWP CES
Mike Nosanov, LADWP
Krishna Nand, Parsons Engineering
Reed Searle, IPA
Lynn Banks, IPSC
James Nelson, IPSC
Tim Conkin, LADWP CES
John Schumann, LADWP
James Holtkamp, LLG&M

[redacted]						ATTACHMENT 1: Worksheet A		
NOI / PSD Calculations								
Operating & Production								
Parameter	**Average Value**	**UoM**	**Post-Change Value**					
Rated Output	875	Mwhe	950					
Fuel Use (Coal)	5,264,292	tons/yr	5,578,473					
Plant Operating Time	16,386	Unit hours	16,386					
Heat Value	11,872	BTU/lb	11,872					
Heat Input (Actual)	7,628	MMBtu/hr	8,083					
Heat Input (Design)	8,352	MMBtu/hr	9,225					
Heat Rate	9,564	Btu/KWhr	9,475					
Flow - Stack	125,000,000	scfh	133,000,000					
Emissions					**PSD Significance**	**PSD Major**	**Difference**	**PSD**
Parameter/Pollutant	**2 Yr Average Value**	**UoM**	**Post-Change Value**	**Change+/-**	**Levels**	**Trigger Value**	**(Trigger - Post)**	**Triggered?**
PSD								
SO2	3586.31	Tons	3513.10	-73.21	40	3626.31	-113.21	N
SO2 % Removal	93.62	%	93.88					
NOx	25143.97	Tons	24346.10	-797.87	40	25183.97	-837.87	N
CO	1317.06	Tons	1394.60	77.54	100	1417.06	-22.46	N
PM10	273.77	Tons	283.51	9.75	15	288.77	-5.25	N
Lead	0.087	Tons	0.123	0.036	0.600	0.687	-0.564	N
VOC	12.65	Tons	13.40	0.75	40	52.65	-39.25	N
Beryllium	0.0102	Tons	0.0014	-0.0088	0.0004	0.0106	-0.0092	N
Mercury	0.081	Tons	0.105	0.024	0.100	0.181	-0.076	N
Fluorides (HF)	9.70	Tons	10.16	0.46	3	12.70	-2.54	N
Sulfuric Acid	4.06	Tons	4.05	-0.01	7	11.06	-7.01	N

PSD / NSPS Observations										ATTACHMENT 1: Worksheet B	
[illegible]											
	SO2 (tons)	SO2 % Removal	Nox (tons)	CO (tons)	PM10 (tons)	Lead (lbs)	VOC (lbs)	Beryllium (lbs)	Mercury (lbs)	Fluorides (HF) (lbs)	Sulfuric Acid (lbs)
1996	3759	92.28	19688	1080	83	224		3.57	270	19139	*
1997	5076	92.05	22675	1291	108	263		4.17	323	22905	*
1998	4261	92.67	25708	1321	114	167		2.23	331	23436	8440
1999	3698	93.57	24179	1312	249	156	25394	2.18	123	19167	8234
2000	3474	93.67	26109	1322	299	191	25204	1.89	201	19621	8015
5 Year Avg	4058	92.8	23672	1265	171	200	25299	2.81	250	20854	8230
Last 2 yr Avg	3586	93.6	25144	1317	274	174	25299	2.03	162	19394	8124
TRIGGER: Average + Sig. Incr.	3626		25184	1417	289	1374	105299	2.83	362	25394	22124
Projected Actuals:	3513	93.88	24346	1395	284	245	26809	2.76	211	20313	8108
Plant Operations [illegible]		Plant Operating	Btu/lb	MBTU/hr	LB/MMBtu	lbs/hr	LB/MMBtu	lbs/hr		Maximum NOx Emission Rate	Maximum SO2 Emission Rate
	Coal Usage (tons)	Hours	Coal HV	Avg Heat Input	NOx Emission rate	NOx Emission Rate	SO2 Emission Rate	SO2 Emission Rate		(Last 5 years)	(Last 5 years)
1996	4310562	15359	11860	6657	0.39	2564	0.07	489		6045	1150
1997	5158867	16504	11789	7343	0.37	2738	0.08	613		4875	1333
1998	5278344	16683	11823	7481	0.41	3082	0.07	513		5331	1279
1999	5244793	16462	11858	7556	0.39	2938	0.06	449		5007	1456
2000	5283790	16309	11885	7701	0.42	3202	0.06	426		5441	1379
5 Year Avg	5055271	16275	11843	7348	0.39	2905	0.07	498	Max.-Prev. 5 yrs.	6045	1456
Last 2 Year Avg	5264292	16386	11872	7628	0.40	3070	0.06	438	Proposed Average:	2972	429
Projected Actuals	5578473	16386	11843	8064	0.37	2972	0.05	429	Proposed Max:	4613	1384
OPERATING CHANGES	Actual	Design									
	Max Heat Input	Max Heat Input (MMBtu/hr)	Fuel Use (coal, tons)	Heat Rate	Mlbs/hr Steam	Mwhe	Stack Flow (scfh)				
Present Operation	7628	8352	5264291.5	9564	6.1	875	125,000,000				
Proposed Operation	8083	9225	5,578,473	9475	6.9	950	133,000,000				

ASSUMPTIONS:

All increases / decreases based on coal use only. Fuel oil & other bulk chemical chemical use not expected to change.
Estimated 15% nominal reduction with new NOx controls over old.
Estimated 4% nominal removal efficiciency improvement in scrubber efficiency.
HAPs PSD triggers calculated per UDAQ Dispersion Modeling Guidelines at R307-410-4.
VOC's calculated from HAPs list.
Projected nominal efficiency improvement. 8.0%
Projected nominal capacity improvement: 8.6%
Projected heat input / coal usage increase: 5.9%
Projected uncontrolled NOx increase: 11.2%

	HP TURBINE DENSE PACK SO2 PROJECTIONS					**ATTACHMENT 1:** Worksheet D			
	99-00 Average lbs/mmbtu								
	inlet	stack	% reduction						
	0.7744	0.0494	93.6209		U1/U2 '99-00 avarage				
	0.7744	0.0474	93.8760		4% reduction stack lbs/mmbtu				
	0.7744	0.0204	97.3657		97.3657% reduction (4% increase in scrubber efficiency)				
	1999								
	Unit One				**Unit Two**				
	Coal Burned (tons)	2,472,213			Coal Burned (tons)	2,772,580			
	Heating Value btu/lb	11,858			Heating Value btu/lb	11,858			
	Inlet SO2 lbs/mmbtu	0.7963			Inlet SO2 lbs/mmbtu	0.7867			
	Stack SO2 lbs/mmbtu	0.0479			Stack SO2 lbs/mmbtu	0.0538			
	Inlet Tons SO2	23,343.93			Inlet Tons SO2	25,864.54			
	Stack Tons SO2	1,404.21	[illegible]	(EDR)	Stack Tons SO2	1,768.80	[illegible]	(EDR)	
	% Removal (lbs/mmbtu)	93.9847			% Removal (lbs/mmbtu)	93.1613			
	% Removal (tons)	93.9847			% Removal (tons)	93.1613			
	% Removal (EDR tons)	93.2899	0.69		% Removal (EDR tons)	91.7578	1.40		
	2000								
	Unit One				**Unit Two**				
	Coal Burned (tons)	2,799,081			Coal Burned (tons)	2,484,709			
	Heating Value btu/lb	11,885			Heating Value btu/lb	11,885			
	Inlet SO2 lbs/mmbtu	0.7712			Inlet SO2 lbs/mmbtu	0.7432			
	Stack SO2 lbs/mmbtu	0.0482			Stack SO2 lbs/mmbtu	0.0477			
	Inlet Tons SO2	25,655.57			Inlet Tons SO2	21,947.27			
	Stack Tons SO2	1,603.47	[illegible]	(EDR)	Stack Tons SO2	1,408.62	[illegible]	(EDR)	
	% Removal (lbs/mmbtu)	93.7500			% Removal (lbs/mmbtu)	93.5818			
	% Removal (tons)	93.7500			% Removal (tons)	93.5818			
	% Removal (EDR tons)	92.7692	0.98		% Removal (EDR tons)	92.6223	0.96		
	1999-2000 Average Intermountain Generating Station								
	% Removal (lbs/mmbtu)	93.6194			Inlet lbs/mmbtu	0.7744			
	% Removal (tons)	93.6194			Stack lbs/mmbtu	0.0494			
	% Removal (EDR tons)	92.6098	1.01						
	Dense Pack - Intermountain Generating Station								
	PREMODIFICATION	1999 - 2000 Average (calculated)			POST MODIFICATION (W/O Scrubber Modification)				
	Coal Burned (tons)	5,268,249			Coal Burned (tons)	5,578,473			
	Heating Value btu/lb	11,871			Heating Value btu/lb	11,871			
	Inlet SO2 lbs/mmbtu	0.7744			Inlet SO2 lbs/mmbtu	0.7744			
	Stack SO2 lbs/mmbtu	0.0494			Stack SO2 lbs/mmbtu	0.0494			
	Inlet Tons SO2	48,430.50	54,170.45	Actual	Inlet Tons SO2	51,282.36	57403.69	Actual Projected	
	Stack Tons SO2	3,089.45	3586.25	(EDR)	Stack Tons SO2	3,271.37	3797.87	(EDR Projected)	
	% Removal (lbs/mmbtu)	93.6209	93.38		% Removal (lbs/mmbtu)	93.6209	93.68		
					POST MODIFICATION (W/Scrubber Modification)				
		Tons of SO2 Reduction			4% reduction stack lbs/mmbtu				
		130.85			Coal Burned (tons)	5,578,473			
		[illegible]73.35	(EDR Projected)		Heating Value btu/lb	11,871			
					Inlet SO2 lbs/mmbtu	0.7744			
					Stack SO2 lbs/mmbtu	0.047424			
					Inlet Tons SO2	51,282.36	57403.69	Actual Projected	
					Stack Tons SO2	3,140.51	3,513.10	(EDR Projected)	
					% Removal (lbs/mmbtu)	93.8760	93.88		
					POST MODIFICATION (W/Scrubber Modification)				
		Tons of SO2 Reduction			97.3657% reduction (4% increase in scrubber efficiency)				
		1,920.44			Coal Burned (tons)	5,578,473			
		2074.06	(EDR Projected)		Heating Value btu/lb	11,871			
					Inlet SO2 lbs/mmbtu	0.7744			
					Stack SO2 lbs/mmbtu	0.0204			
					Inlet Tons SO2	51,282.36	57403.69	Actual Projected	
					Stack Tons SO2	1,350.93	1,512.19	(EDR Projected)	
					% Removal (lbs/mmbtu)	97.3657			
NOTES:									
1	Stack SO2 tons calculated from lbs/mmbtu are less than SO2 tons calculated for EDR from CEM SO2 ppm and Stack flow.								
2	Dense Pack SO2 tons are calculated from lbs/mmbtu. (yellow boxes)								

ATTACHMENT 1: Worksheet E

CO Calculations

Dense Pack - Intermountain Generating Station			
PREMODIFICATION	1999 - 2000 Average	POST MODIFICATION	
Coal Burned (tons)	5,268,249	Coal Burned (tons)	5,578,473
CO E.F. (lb/ton)	0.50	CO E.F. (lb/ton)	0.50
CO Emissons (tons)	1317.06	CO Emissons (tons)	1394.62

Tons of CO increase
77.56

AP-42 Table 1.1-3

DENSE PACK PM10
COAL USAGE CALCULATION SUMMARY

ATTACHMENT 1: Worksheet F

YEARLY INVENTORY

5,578,473	Tons coal received Railcar Unloading
5,578,473	Tons of coal fed to both Units
2,789,237	Tons of coal fed to Unit 1
2,789,237	Tons of coal fed to Unit 2
11,800	Coal heating value (Btu/lb)
25.1	Coal pile (acres)
0.0056	Unit 1 Particulate lbs/mmbtu (tsp)
0.0036	Unit 2 Particulate lbs/mmbtu (tsp)

UNIT 1 FABRIC FILTER PARTICULATE EMISSION (online)
169.5677 TPY Particulate PM10 AP 42 Table 1.1-6

UNIT 2 FABRIC FILTER PARTICULATE EMISSION (online)
109.0078 TPY Particulate PM10 AP 42 Table 1.1-6

COAL TRAIN UNLOADING DUST COLLECTORS A,B,C,D
0.0625 TPY Particulate PM10

COAL TRUCK UNLOADING DUST COLLECTOR
0.0000 TPY Particulate PM10 Included in train unloading

COAL RESERVE RECLAIM DUST COLLECTOR
0.0020 TPY Particulate PM10 10% of Coal Crusher Emissions

COAL SAMPLE PREPARATION DUST COLLECTOR
0.0000 TPY Particulate PM10

COAL TRANSFER BUILDING #1 DUST COLLECTOR
0.0156 TPY Particulate PM10

COAL TRANSFER BUILDING #2 DUST COLLECTOR
0.0312 TPY Particulate PM10

COAL TRANSFER BUILDING #4 DUST COLLECTOR
0.0195 TPY Particulate PM10

COAL CRUSHER BUILDING DUST COLLECTOR
0.0195 TPY Particulate PM10

ACTIVE COAL STACKOUT (fugitive)
3.9049 TPY Particulate PM10

DUST COLLECTOR 13A & 13B
0.0312 TPY Particulate PM10

DUST COLLECTOR 14A & 14B
0.0156 TPY Particulate PM10

COAL PILE FUGITIVE EMISSIONS
0.8368 TPY Particulate PM10

283.5145 TPY PM10 (COAL ONLY)

COMMENTS
EF found in AP-42 Table 11.19.2-1 site dust collectors for coal, limestone, lime vacuum sys. and soda ash PM10 and PM2.5.
Using same ratio of PM10 to PM2.5 found with emissions at stack.
Use cumulative Mass % <= Stated Size in AP-42 Table 1.1-5 for percentages of PM10 and PM2.5 as a ratio of TSP.
PM10 = 92% of TSP
PM2.5 = 53% of TSP

IGS Uprate Project Coordination

ATTACHMENT 2

Task Name	Start	Finish
Unit 2 Projects	**1/2/2001**	**4/1/2004**
HP Turbine Retrofit	1/15/2001	4/1/2002
Cooling Tower Performance Upgrade	2/1/2001	4/1/2004
Boiler Safety Valve Addition	4/2/2001	4/1/2002
Generator Cooling Enhancements	4/2/2001	4/1/2002
Isophase Cooling Enhancements	4/2/2001	4/1/2002
Large Motor Bus Loading Equalization	4/2/2001	4/1/2002
Boiler Feed Pump Performance Upgrade	1/2/2001	4/1/2003
Main Step-up Transformer Cooling	3/1/2001	4/1/2002
NOx Reduction Project	4/2/2001	4/1/2004
Scrubber Wall Ring	5/2/2001	4/2/2003
Generator SCW O2 Monitoring	4/2/2001	4/1/2002
HP Heater Drain Line Mods	4/2/2001	4/1/2002
Boiler Modifications	4/2/2001	4/1/2004
Cooling Tower Makeup Modifications	1/2/2002	4/1/2004
Cooling Tower Electrical Redundancy	1/2/2002	4/1/2004
Unit 1 Projects	**1/2/2001**	**4/2/2003**
HP Turbine Retrofit	1/15/2001	4/1/2003
Cooling Tower Performance Upgrade	2/1/2001	4/1/2003
Boiler Safety Valve Addition	3/1/2001	4/1/2003
Generator Cooling Enhancements	1/2/2002	4/2/2003
Isophase Cooling Enhancements	1/2/2002	4/2/2003
Large Motor Bus Loading Equalization	1/2/2002	4/1/2003
Boiler Feed Pump Performance Upgrade	1/2/2001	4/1/2003
Main Step-up Transformer Cooling	1/2/2002	4/1/2003
NOx Reduction Project	3/1/2001	4/1/2003
Scrubber Wall Ring	5/1/2001	4/1/2003
Generator SCW O2 Monitoring	1/2/2002	4/1/2003
HP Heater Drain Line Mods	4/2/2001	3/1/2002
Boiler Modifications	4/2/2001	4/1/2003
Cooling Tower Electrical Redundancy	1/2/2002	3/31/2003

ATTACHMENT 1: Worksheet C

HAP/Other Projection Data/COAL

POLLUTANT	Concentration (ppm)	Pollutant Emission Factor (lbs/10^12 Btu)	Control Device Efficiency (CE) (% emission of fuel conc.)	Table or Method Used*	Actual Emission Factor (EF)	Calculation	Projected Emissions (lbs/hr)	MW	ACGIH Class	z	Previous 1999	Actuals 2000	Average	Change +/-	Release Rate	ACGIH TLV	Units	ETF	ETV	TSL	Difference	Modeling Required?
[illegible]																						
Antimony	3.1	0.92*(C/A*PM)^0.63		AP-42 1.1-15	0.300	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	39.70		Chronic	30	35.246886	35.22769636	35.2369118	4.47	0.0002725	0.5	mg/m3	0.368	0.184	0.01666667	-0.1637215	
Arsenic	12	3.1*(C/A*PM)^0.85		AP-42 1.1-15	2.157	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	285.75		A1	80	271.4042005	258.7669662	265.0855833	20.16	0.00128335	0.01	mg/m3	0.123	0.00123	0.000111111	3.24976E-07	Y
Barium	113	(C/A*PM)		Eng. Calc.(1)	8.147	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	814.20				686.1213449	611.2064079	648.6638764	165.54	0.010102368							
Beryllium	0.36	1.2*(C/A*PM)^1.1		AP-42 1.1-15	0.017	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	2.23		A1	90	1.878347314	2.179624561	2.028985948	0.20	1.22206E-05	0.002	mg/m3	0.123	0.000246	2.22222E-05	-0.00023378	
Cadmium	0.66	3.3*(C/A*PM)^0.5		AP-42 1.1-15	0.525	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	82.82		A2	90	74.3729226	62.1744665	68.2735446	14.55	0.000507878	0.01	mg/m3	0.123	0.00123	0.000111111	-0.000342124	
Chromium	24	3.7*(C/A*PM)^0.58		AP-42 1.1-15	4.319	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	572.06		A1	90	534.0143915	524.299845	529.1571183	42.89	0.00351514	0.05	mg/m3	0.123	0.00615	0.000555556	-0.005533486	
Cobalt	2.9	1.7*(C/A*PM)^0.69		AP-42 1.1-15	0.475	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	62.97		Chronic	30	56.73090035	53.65300623	54.64195329	8.33	0.000506172	0.02	mg/m3	0.368	0.00736	0.000666667	-0.006851828	
Copper	7.8	(C/A*PM)		Eng. Calc.(1)	0.424	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	56.20				52.4658837	33.13196638	42.79892654	13.40	0.000317929							
Lead	7.1	3.4*(C/A*PM)^0.80		AP-42 1.1-15	1.588	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	210.39		Chronic	30	190.6875338	156.0387354	173.3631846	37.03	0.002259576	0.05	mg/m3	0.368	0.0184	0.001666667	-0.016140424	
Manganese	8.9	3.8*(C/A*PM)^0.60		AP-42 1.1-15	2.621	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	347.20		Chronic	30	334.4265091	251.099098	292.7627685	54.44	0.00332407	0.1	mg/m3	0.368	0.0368	0.003333333	-0.033477593	
Mercury	0.061		31%	Eng. Calc.(2)		E=Conc(ppm)*Thruput(Mtons)*Control Efficiency(CE)*2000lbs/ton	210.98		Chronic	30	201.0140416	123.4200948	162.2170682	48.76	0.002975759	0.025	mg/m3	0.368	0.0092	0.000833333	-0.009224241	
Nickel	4.7	4.4*(C/A*PM)^0.48		AP-42 1.1-15	2.286	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	302.84		Chronic	30	322.8086641	270.9079077	296.8584359	5.98	0.000364871	0.1	mg/m3	0.368	0.0368	0.003333333	-0.036436129	
Selenium	2.4		12%	Eng. Calc.(3)		E=Conc(ppm)*Thruput(Mtons)*Control Efficiency(CE)*2000lbs/ton	3213.20		Chronic	30	3035.360736	3393.982104	3214.67142	-1.47	-8.977E-05	0.2	mg/m3	0.368	0.0736	0.006666667	-0.07366877	
Vanadium	5.6	(C/A*PM)		Eng. Calc.(1)	0.305	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	40.35				771.6565483		771.6565483	-731.31	-0.044628874							
Zinc	7.4	(C/A*PM)		Eng. Calc.(1)	0.403	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	53.32				50.13591086	44.30573505	47.22082287	6.10	0.000372181							
[illegible]																						
Acenaphthene		0.00000051 (lbs/ton)		AP-42 1.1-12	5.10E-07	E=EF(lbs/ton)*Thruput(tons)	2.85				2.6947329	2.67484443	2.684788865	0.16	9.77863E-06							
Acenaphthylene		2.5E-07 (lbs/ton)		AP-42 1.1-12	2.50E-07	E=EF(lbs/ton)*Thruput(tons)	1.395				1.3209475	1.31119825	1.316072875	0.08	4.79344E-06							
Acetaldehyde@		0.00057 (lbs/ton)		AP-42 1.1-13	5.70E-04	E=EF(lbs/ton)*Thruput(tons)	3,179.73	44.05	Acute	10	3011.7603	2989.53201	3000.646155	179.08	0.010929053	25	ppm C	0.31	13.96267894	4.50408998	-13.95174986	
Acetophenone@		0.000015 (lbs/ton)		AP-42 1.1-13	1.50E-05	E=EF(lbs/ton)*Thruput(tons)	83.86	120.15	Chronic	30	79.25685	78.671895	78.9643725	4.71	0.000287607	10	ppm	0.368	18.08392636	1.63803681	-18.08363877	
Acrolein@		0.00029 (lbs/ton)		AP-42 1.1-13	2.90E-04	E=EF(lbs/ton)*Thruput(tons)	1,617.76	56.06	Acute	10	1532.2991	1520.98997	1526.644535	91.11	0.005560395	0.1	ppm C	0.31	0.071078119	0.022928425	-0.065517723	
Anthracene		0.0000021 (lbs/ton)		AP-42 1.1-12	2.10E-07	E=EF(lbs/ton)*Thruput(tons)	1.171				1.1095959	1.10140653	1.105501215	0.07	4.02649E-06							
Benzene@		3.6 (lbs/10^12 BTU)		Eng. Calc.(3)	3.60E+00	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	503.33	78.11	Chronic	30	477.5258696	472.828236	475.1770529	28.15	0.00171811	0.5	ppm	0.368	0.567821677	0.053244717	-0.566103567	
Benzo(a)anthracene		8.0E-08 (lbs/ton)		AP-42 1.1-12	8.00E-08	E=EF(lbs/ton)*Thruput(tons)	0.446				0.4227032	0.41958344	0.42114332	0.03	1.5339E-06							
Benzo(a)pyrene		0.0018 (lbs/10^12 BTU)		Eng. Calc.(3)	1.80E-03	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	0.238				0.228195465	0.22387127	0.225083867	0.01	8.13841E-07							
Benzo(b,j,k)fluoranthene		1.1E-07 (lbs/ton)		AP-42 1.1-12	1.10E-07	E=EF(lbs/ton)*Thruput(tons)	0.614				0.5812169	0.57692723	0.579072065	0.03	2.10912E-06							
Benzo(g,h,i)perylene		2.7E-08 (lbs/ton)		AP-42 1.1-12	2.70E-08	E=EF(lbs/ton)*Thruput(tons)	0.151				0.14266233	0.141609411	0.142135871	0.01	5.17692E-07							
Benzyl chloride@		0.0007 (lbs/ton)		AP-42 1.1-13	7.00E-04	E=EF(lbs/ton)*Thruput(tons)	3,904.93	126.58	Chronic	30	3698.653	3671.3551	3685.00405	219.93	0.013421943	1	ppm	0.368	1.90517137	0.17258967	-1.891749727	
Biphenyl@		0.0000017 (lbs/ton)		AP-42 1.1-12	1.70E-06	E=EF(lbs/ton)*Thruput(tons)	9.48	154.2	Chronic	30	8.982443	8.9161461	8.94929555	0.53	3.25954E-05	0.2	ppm	0.368	0.464176887	0.04204489	-0.464144092	
Bis(2-ethylhexyl)phthalate (DEHP)@		0.000073 (lbs/ton)		AP-42 1.1-13	7.30E-05	E=EF(lbs/ton)*Thruput(tons)	407.23				385.71667	382.869889	384.2932795	22.94	0.001399668							
Bromoform@		0.000039 (lbs/ton)		AP-42 1.1-13	3.90E-05	E=EF(lbs/ton)*Thruput(tons)	217.56	252.8	Chronic	30	206.06781	204.546927	205.3073685	12.25	0.000747777	0.5	ppm	0.368	1.902462166	0.172324472	-1.90171439	
Carbon disulfide@		0.00013 (lbs/ton)		AP-42 1.1-13	1.30E-04	E=EF(lbs/ton)*Thruput(tons)	725.20	76.14	Chronic	30	686.8927	681.82309	684.357895	40.84	0.002492561	10	ppm	0.368	11.45892636	1.03803681	-11.45743379	
2-Chloroacetophenone@		0.000007 (lbs/ton)		AP-42 1.1-13	7.00E-06	E=EF(lbs/ton)*Thruput(tons)	39.05	154.59	Chronic	30	36.98653	36.713551	36.8500405	2.20	0.000134216	0.05	ppm	0.368	0.116337668	0.010537832	-0.116203452	
Chlorobenzene@		0.000022 (lbs/ton)		AP-42 1.1-13	2.20E-05	E=EF(lbs/ton)*Thruput(tons)	122.73	112.56	Chronic	30	116.24338	115.385446	115.814413	6.91	0.000421823	10	ppm	0.368	16.94154601	1.534560327	-16.94112419	
Chloroform@		0.000059 (lbs/ton)		AP-42 1.1-13	5.90E-05	E=EF(lbs/ton)*Thruput(tons)	329.13	119.38	Chronic	30	311.74361	309.442787	310.5931985	18.54	0.001131263	10	ppm	0.368	17.96603272	1.627539196	-17.96490147	
Chrysene		0.0000001 (lbs/ton)		AP-42 1.1-12	1.00E-07	E=EF(lbs/ton)*Thruput(tons)	0.558	228.3	Chronic	30	0.528379	0.5244793	0.52642915	0.03	1.91738E-06	L	ppm	0.368	#VALUE!	#VALUE!	#VALUE!	
Cumene@		0.0000053 (lbs/ton)		AP-42 1.1-13	5.30E-06	E=EF(lbs/ton)*Thruput(tons)	29.57	120.19	Chronic	30	28.004067	27.7974029	27.90074485	1.67	0.000101621	50	ppm	0.368	90.44973415	8.192910702	-90.44963253	
Cyanide		0.0025 (lbs/ton)		AP-42 1.1-13	2.50E-03	E=EF(lbs/ton)*Thruput(tons)	13,946.18				13209.475	13111.9825	13160.72875	785.45	0.047934441							
2,4-Dinitrotoluene@		0.00000028 (lbs/ton)		AP-42 1.1-13	2.80E-07	E=EF(lbs/ton)*Thruput(tons)	1.562				1.4794612	1.46854204	1.47400162	0.09	5.36868E-06							
Dimethyl sulfate@		0.000048 (lbs/ton)		AP-42 1.1-13	4.80E-05	E=EF(lbs/ton)*Thruput(tons)	267.77	126.1	Chronic	30	253.62182	251.750064	252.685992	15.06	0.000920341	0.1	ppm	0.368	0.189794683	0.017191547	-0.188874342	
Ethyl benzene@		0.000094 (lbs/ton)		AP-42 1.1-13	9.40E-05	E=EF(lbs/ton)*Thruput(tons)	524.38	106.16	Chronic	30	496.67626	493.010542	494.843401	29.53	0.001802335	100	ppm	0.368	159.7827403	14.4730743	-159.780938	
Ethyl chloride@		0.000042 (lbs/ton)		AP-42 1.1-13	4.20E-05	E=EF(lbs/ton)*Thruput(tons)	234.30	64.52	Chronic	30	221.91916	220.281306	221.100243	13.20	0.000805289	100	ppm	0.368	97.10985685	8.796162066	-97.10906155	
Ethylene dichloride@		0.00004 (lbs/ton)		AP-42 1.1-13	4.00E-05	E=EF(lbs/ton)*Thruput(tons)	223.14	98.96	Chronic	30	211.3516	209.79172	210.57166	12.57	0.000766961	10	ppm	0.368	14.89459305	1.349147921	-14.8938261	
Ethylene dibromide@		0.0000012 (lbs/ton)		AP-42 1.1-13	1.20E-06	E=EF(lbs/ton)*Thruput(tons)	6.69	187.88	Chronic	30	6.340548	6.2937516	6.3171498	0.38	2.30085E-05	L	ppm	0.368	#VALUE!			
Fluoranthene		0.00000071 (lbs/ton)		AP-42 1.1-12	7.10E-07	E=EF(lbs/ton)*Thruput(tons)	3.96				3.7514909	3.72380303	3.737646965	0.22	1.36134E-05							
Fluorene		9.1E-07 (lbs/ton)		AP-42 1.1-12	9.10E-07	E=EF(lbs/ton)*Thruput(tons)	5.08				4.8082469	4.77278168	4.790608265	0.29	1.74481E-05							
Formaldehyde@		3.0 (lbs/10^12 BTU)		Eng. Calc.(3)	3.00E+00	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	397.37	30.03	Acute / A2	90	376.9941077	373.2854495	375.1397786	22.23	0.001356462	0.3	ppm	0.123	0.04532135	0.00409407	-0.043964947	
Hexane@		0.000067 (lbs/ton)		AP-42 1.1-13	6.70E-05	E=EF(lbs/ton)*Thruput(tons)	373.76	86.18	Chronic	30	354.01393	351.401131	352.7075306	21.05	0.001284643	500	ppm	0.368	648.6529652	58.7457395	-648.5516806	
Indeno(1,2,3-cd)pyrene		6.1E-08 (lbs/ton)		AP-42 1.1-12	6.10E-08	E=EF(lbs/ton)*Thruput(tons)	0.340				0.32231119	0.319932373	0.321121782	0.02	1.1696E-06							
Isophorone@		0.00058 (lbs/ton)		AP-42 1.1-13	5.80E-04	E=EF(lbs/ton)*Thruput(tons)	3,235.51	138.21	Acute	10	3064.5962	3041.97994	3053.28807	182.23	0.01112079	5	ppm	0.31	8.761779141	2.826380366	-8.750658351	
Methyl bromide@		0.00016 (lbs/ton)		AP-42 1.1-13	1.60E-04	E=EF(lbs/ton)*Thruput(tons)	892.56	94.95	Chronic	30	845.4064	839.16686	842.28664	50.27	0.003067804	1	ppm	0.368	1.429104294	0.129447853	-1.42603649	
Methyl chloride@		0.00053 (lbs/ton)		AP-42 1.1-13	5.30E-04	E=EF(lbs/ton)*Thruput(tons)	2,956.50	50.49	Chronic	30	2800.4067	2779.74029	2790.074495	166.52	0.010162101	50	ppm	0.368	37.99656442	3.441717791	-37.98640232	
5-Methyl chrysene		2.2E-08 (lbs/ton)		AP-42 1.1-12	2.20E-08	E=EF(lbs/ton)*Thruput(tons)	0.123				0.11624338	0.115385446	0.115814413	0.01	4.21823E-07							
Methyl ethyl ketone@		0.00039 (lbs/ton)		AP-42 1.1-13	3.90E-04	E=EF(lbs/ton)*Thruput(tons)	2,175.80	72.1	Chronic	30	2060.6781	2045.46927	2053.073685	122.53	0.007477773	200	ppm	0.368	217.0372168	19.65910837	-217.029741	
Methyl hydrazine@		0.00017 (lbs/ton)		AP-42 1.1-13	1.70E-04	E=EF(lbs/ton)*Thruput(tons)	948.34	46.07	Chronic	30	898.2443	891.61461	894.929555	53.41	0.003259542	0.01	ppm	0.368	0.006934053	0.000628085	-0.003674511	
Methyl methacrylate@		0.00002 (lbs/ton)		AP-42 1.1-13	2.00E-05	E=EF(lbs/ton)*Thruput(tons)	111.57	100.13	Chronic	30	105.6758	104.89586	105.28583	6.28	0.000383478	50	ppm	0.368	76.35346603	6.825494206	-76.35307255	
Methyl tert butyl ether@		0.000035 (lbs/ton)		AP-42 1.1-13	3.50E-05	E=EF(lbs/ton)*Thruput(tons)	195.25	88.17	Chronic	30	184.93265	183.567755	184.2502025	11.00	0.000671082	40	ppm	0.368	53.08250675	4.808179959	-53.08183567	
Methylene chloride		0.00029 (lbs/ton)		AP-42 1.1-13	2.90E-04	E=EF(lbs/ton)*Thruput(tons)	1,617.76	84.93	Chronic	30	1532.2991	1520.98997	1526.644535	91.11	0.005560395	50	ppm	0.368	63.91460123	5.789366063	-63.90904083	
Naphthalene@		0.000013 (lbs/ton)		AP-42 1.1-12	1.30E-05	E=EF(lbs/ton)*Thruput(tons)	72.52	128.19	Chronic	30	68.68927	68.182309	68.4357895	4.08	0.000249259	10	ppm	0.368	19.29409681	1.747648262	-19.29378755	
Phenanthrene		0.0000027 (lbs/ton)		AP-42 1.1-12	2.70E-06	E=EF(lbs/ton)*Thruput(tons)	15.06				14.268233	14.1609411	14.21358706	0.85	5.17692E-05							
Phenol@		0.000016 (lbs/ton)		AP-42 1.1-13	1.60E-05	E=EF(lbs/ton)*Thruput(tons)	89.26	94.11	Chronic	30	84.54064	83.916868	84.228664	5.03	0.00030679	5	ppm	0.368	7.082306748	0.641513292	-7.081999958	
Propionaldehyde@		0.00038 (lbs/ton)		AP-42 1.1-13	3.80E-04	E=EF(lbs/ton)*Thruput(tons)	2,119.82				2007.6402	1993.02134	2000.43077	119.39	0.007286045							
Pyrene		0.00000033 (lbs/ton)		AP-42 1.1-12	3.30E-07	E=EF(lbs/ton)*Thruput(tons)	1.841				1.7436507	1.73078169	1.737216195	0.10	6.32735E-06							
Tetrachloroethylene*		0.000043 (lbs/ton)		AP-42 1.1-13	4.30E-05	E=EF(lbs/ton)*Thruput(tons)	239.87	165.8	Chronic	30	227.20287	225.526099	226.3646345	13.51	0.000824472	25	ppm	0.368	62.38891207	5.650988412	-62.38808759	
Toluene@		1.4 (lbs/10^12 BTU)		Eng. Calc.(3)	1.40E+00	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	185.44	92.13	Chronic	30	175.9305636	174.1986764	175.06523	10.37	0.000632988	50	ppm	0.368	69.33300613	6.280163699	-69.33237315	
1,1,1-Trichloroethane		0.00002 (lbs/ton)		AP-42 1.1-13	2.00E-05	E=EF(lbs/ton)*Thruput(tons)	111.57	133.42	Chronic	30	105.6758	104.89586	105.28583	6.28	0.000383478	350	ppm	0.368	702.8423722	63.66325836	-702.8419887	
Styrene@		0.000025 (lbs/ton)		AP-42 1.1-13	2.50E-05	E=EF(lbs/ton)*Thruput(tons)	139.46	104.16	Chronic	30	132.09475	131.119825	131.6072875	7.85	0.000479344	20	ppm	0.368	31.35450307	2.8400818	-31.35402372	
Xylenes@		0.000037 (lbs/ton)		AP-42 1.1-13	3.70E-05	E=EF(lbs/ton)*Thruput(tons)	206.40	106.16	Chronic	30	195.50023	194.057341	194.7787855	11.62	0.00070943	100	ppm	0.368	159.7827403	14.4730743	-159.7820309	
Vinyl acetate@		0.0000076 (lbs/ton)		AP-42 1.1-13	7.60E-06	E=EF(lbs/ton)*Thruput(tons)	42.40	86.09	Chronic	30	40.156804	39.8604268	40.0086154	2.39	0.000145721	10	ppm	0.368	12.95751329	1.173667796	-12.95736757	
[illegible]							26569.0441				25167.22566	24978.94757	25073.08678									
Total PCDD/PCDF		0.000002 (lbs/10^12 BTU)		Eng. Calc.(3)	2.00E-06	E=(EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb))/10^12	264.9E-6				0.000251329	0.000248857	0.000250093	0.00	9.04266E-16							
[illegible]																						
Hydrogen Chloride	299		3%	Eng. Calc.(3)		E=Conc(ppm)*Thruput(Mtons)*Control Efficiency(CE)*2000lbs/ton	96,406.29				96912.55014	95576.89642	96244.72428	163.86	0.00[illegible]							
Hydrogen Fluoride	63		3%	Eng. Calc.(3)		E=Conc(ppm)*Thruput(Mtons)*Control Efficiency(CE)*2000lbs/ton	20,313.45				19621.02804	19166.91886	19393.97346	919.48	0.056113641							
Sulfuric Acid	0.50%	0.0646 (lbs/ton)	4.50%	Eng. Calc.(4)	0.0645865	E=EF(lbs/ton)*Thruput(tons)*Conc(%)*100*Control Efficiency(CE)	8,108.13				7984.561802	8215.778742	8100.169272	2.97	0.000180976							

[illegible]

(1) By ash fraction derivative
(2) By stack test
(3) By EPRI's Trace Report
(4) By SoCo's Paper
Realized HAP emission increases calculated per Utah R307-410-4.
To convert ppm to mg/m3: TLV(ppm) X MW / 24.45
z = impact (acute/chronic/carcinogenic)
ETF = Emission Threshold Factor (Table IV-2, R307-410-4, Boundaries >100m)
TLV = Threshold Limit Values (ACGIH 2001 version)
ETV = Emission Threshold Value ([lb/hr] = [TLV] X [ETF])
TSL = Toxic Screening Level (TLV/z)
MW = Atomic molecular weight of compound
* = VOC

[illegible]

Coal Throughput = 5,578,473 tons
Heating Value = 11,822 Btu/lb
Ash = 6.64%
Plant operating hours = 16,366
Fabric Filter Efficiency = 0.0047 lbs/MMBtu

From: Rand Crafts
To: mradulov@deq.state.ut.us
Date: Wed, Apr 11, 2001 8:32 AM
Subject: NOI Excel Spreadsheet

Milka,

Attached is the Excel file for the NOI IPSC submitted for plant modifications.
I am compiling the other material you have requested and will forward it to you shortly.
Thank you again for your time on Monday.

Rand Crafts
Intermountain Power Service Corp
rand-c@ipsc.com
435-864-6494
435-864-0994 Fax

ATTACHMENT: 4B_DP_PSDCALC.XLS

INTERMOUNTAIN POWER SERVICE CORPORATION

April 11, 2001

Milka Radulovic
New Source Review Engineer
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, Utah 84114-4820

Dear Ms. Radulovic,

<u>Additional Information: IPP Notice of Intent for Modification</u>

Enclosed herewith are process diagrams for both the combustion-side flow path, and the steam cycle side flow path. Additionally, I have included a plant arrangement diagram and elevation diagrams of the steam generating units.

I am proceeding with fulfilling your other requests for an actual construction time line, and a cursory BACT analysis for NOx controls, which will be forwarded under separate cover.

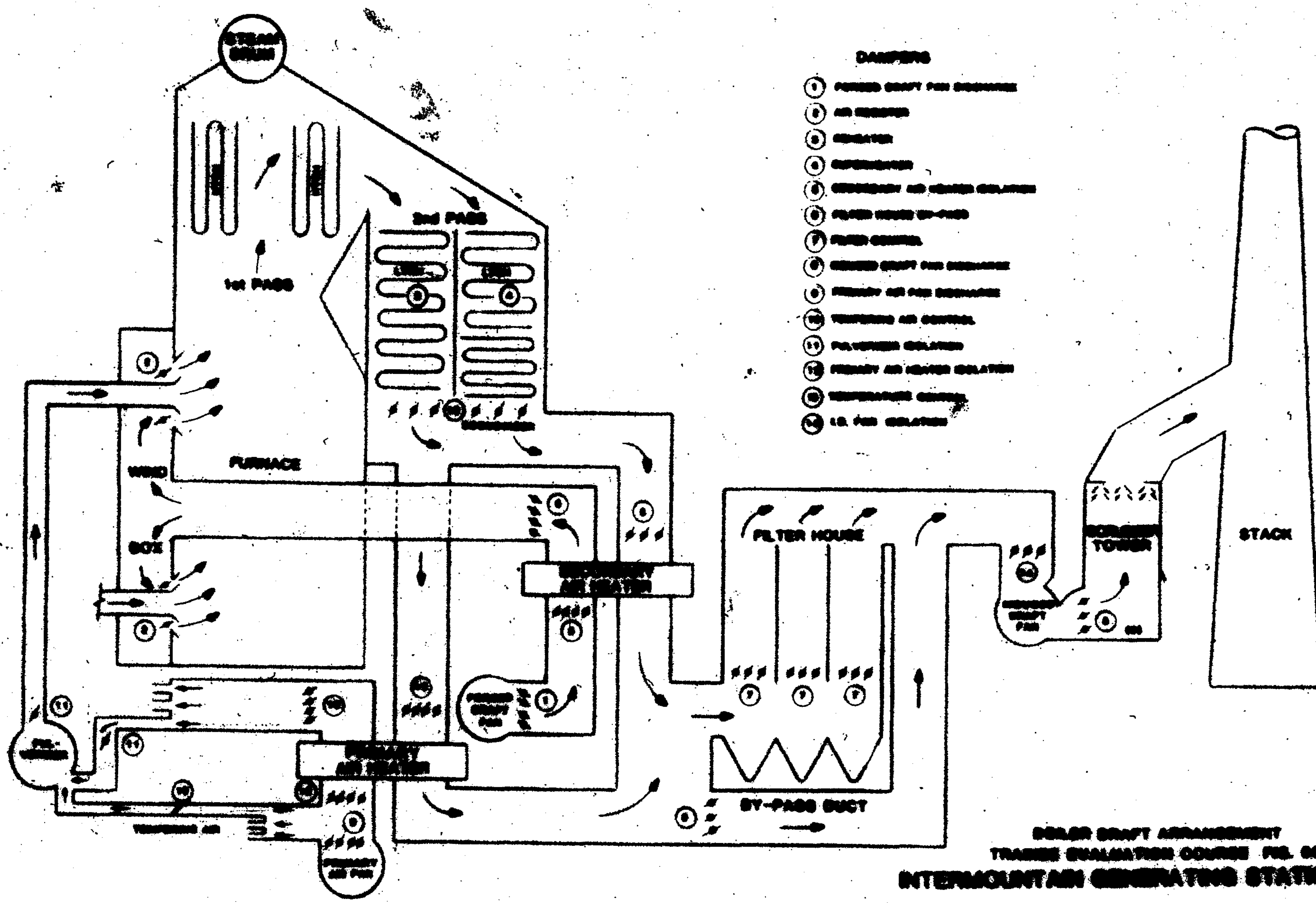
Thank you again for taking the time to meet with me this week. If you need anything further in the meantime, please call.

Cordially,

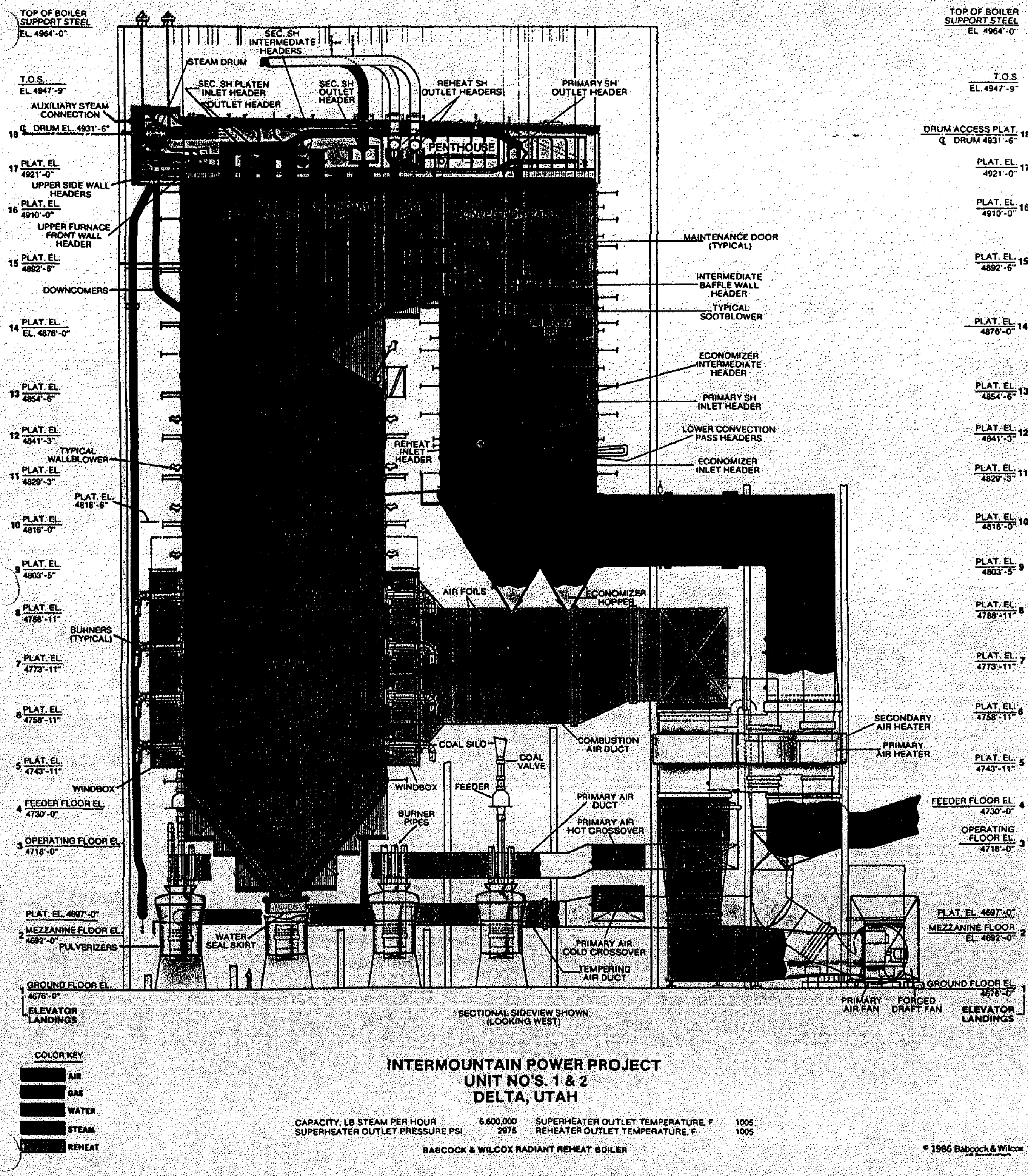
Rand Crafts
Environmental Analyst
435-864-6494 wk
435-864-0994 fx
rand-c@ipsc.com

cc: File

850 West Brush Wellman Road, Delta, Utah 84624 · Telephone (801) 864-4414 · FAX (801) 864-4970



INTERMOUNTAIN GENERATING STATION

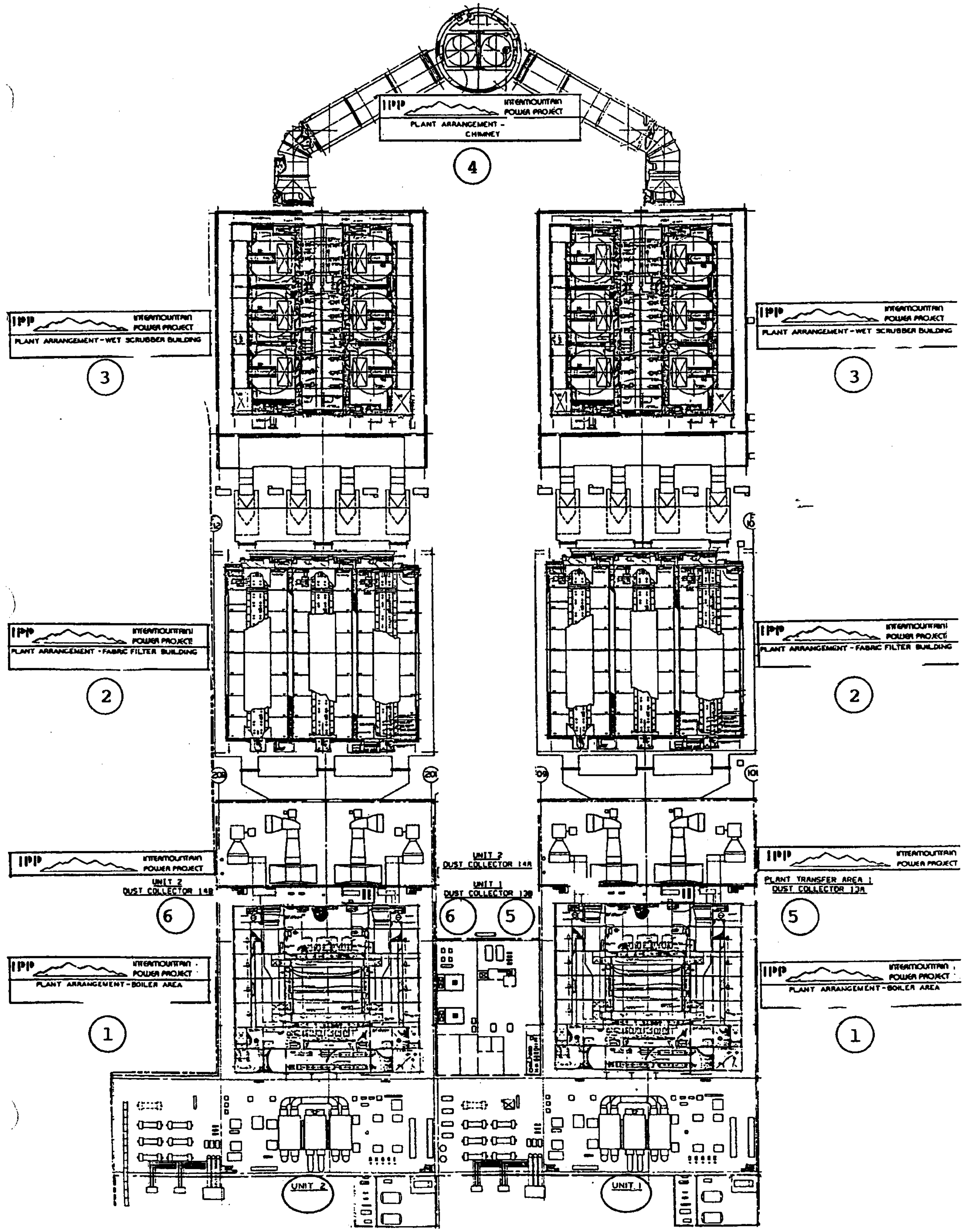


INTERMOUNTAIN POWER PROJECT
UNIT NO'S. 1 & 2
DELTA, UTAH

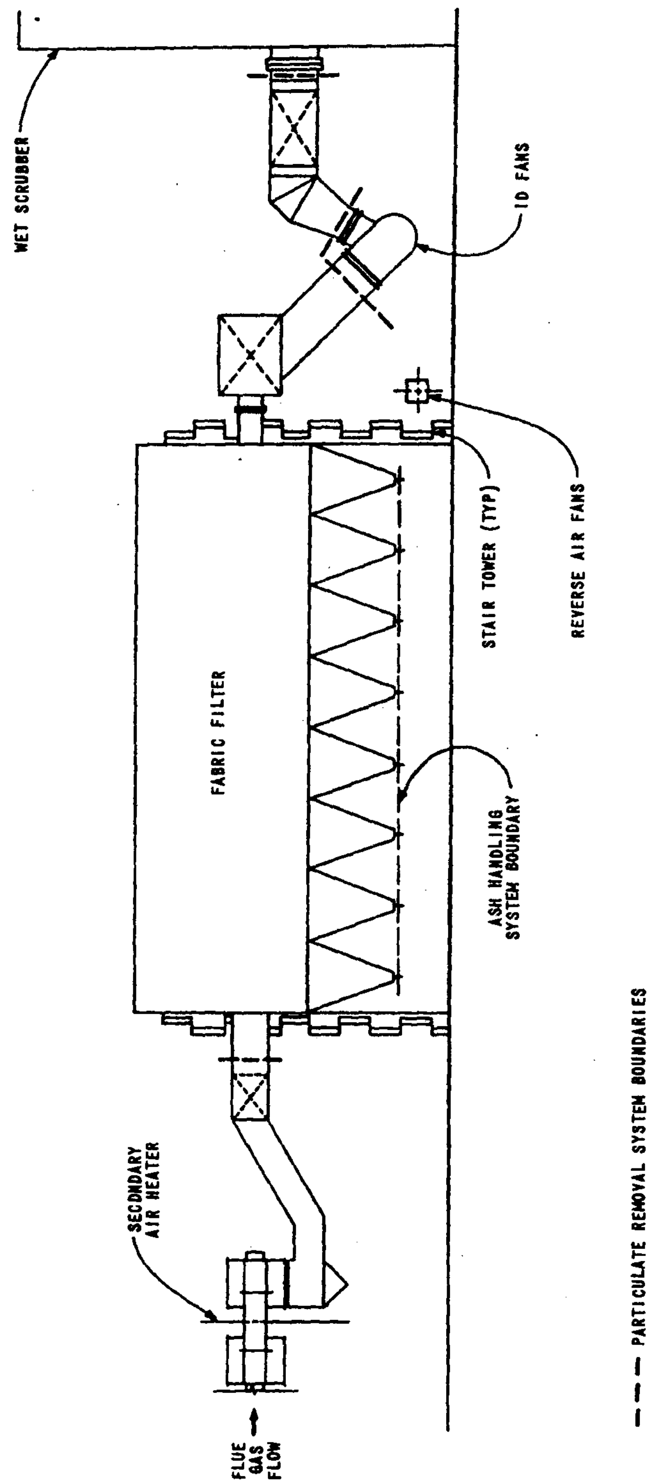
CAPACITY, LB STEAM PER HOUR	6,600,000	SUPERHEATER OUTLET TEMPERATURE, F	1005
SUPERHEATER OUTLET PRESSURE PSI	2975	REHEATER OUTLET TEMPERATURE, F	1005

BABCOCK & WILCOX RADIANT REHEAT BOILER

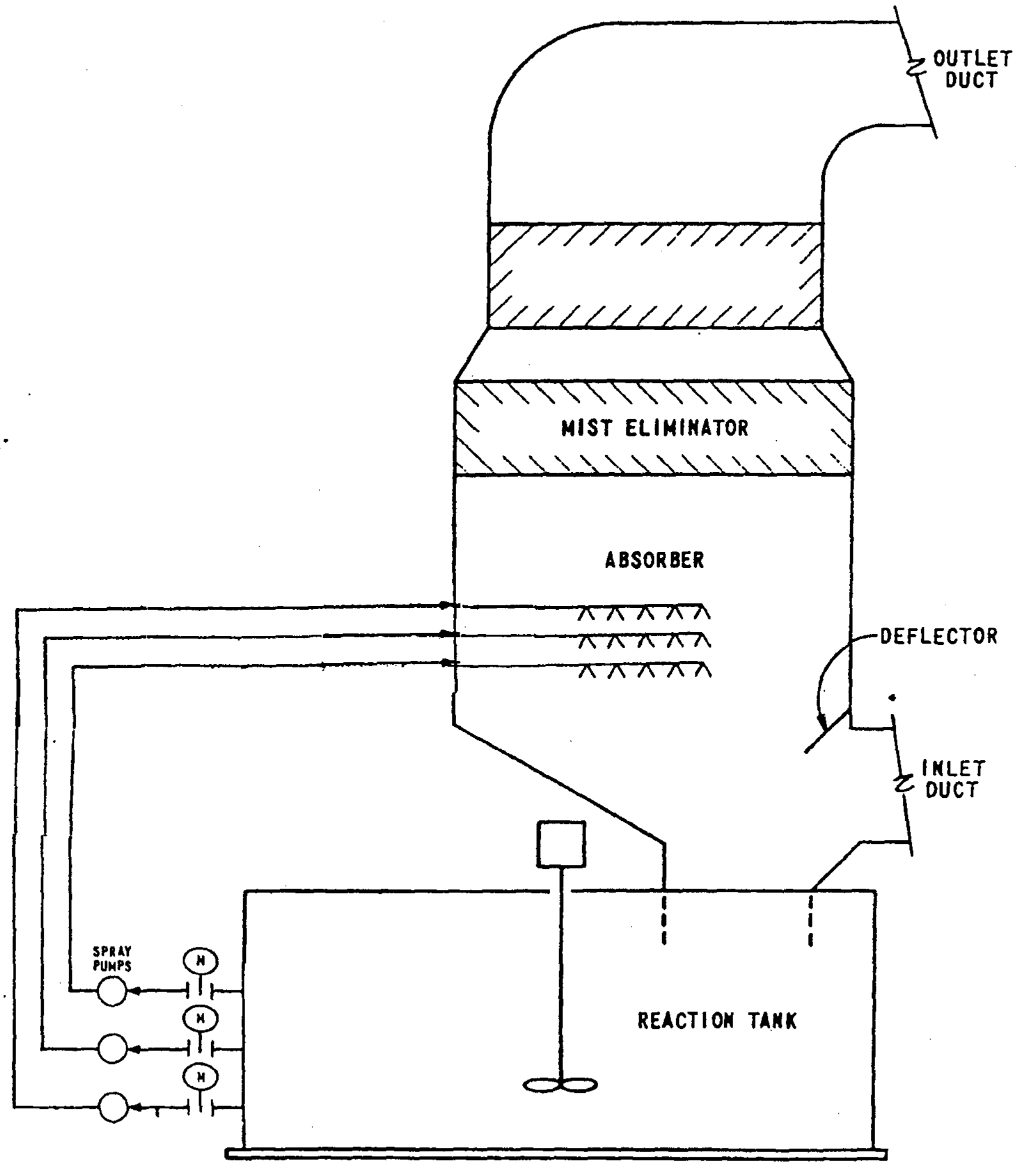
POINT SOURCE REFERENCE DIAGRAMS



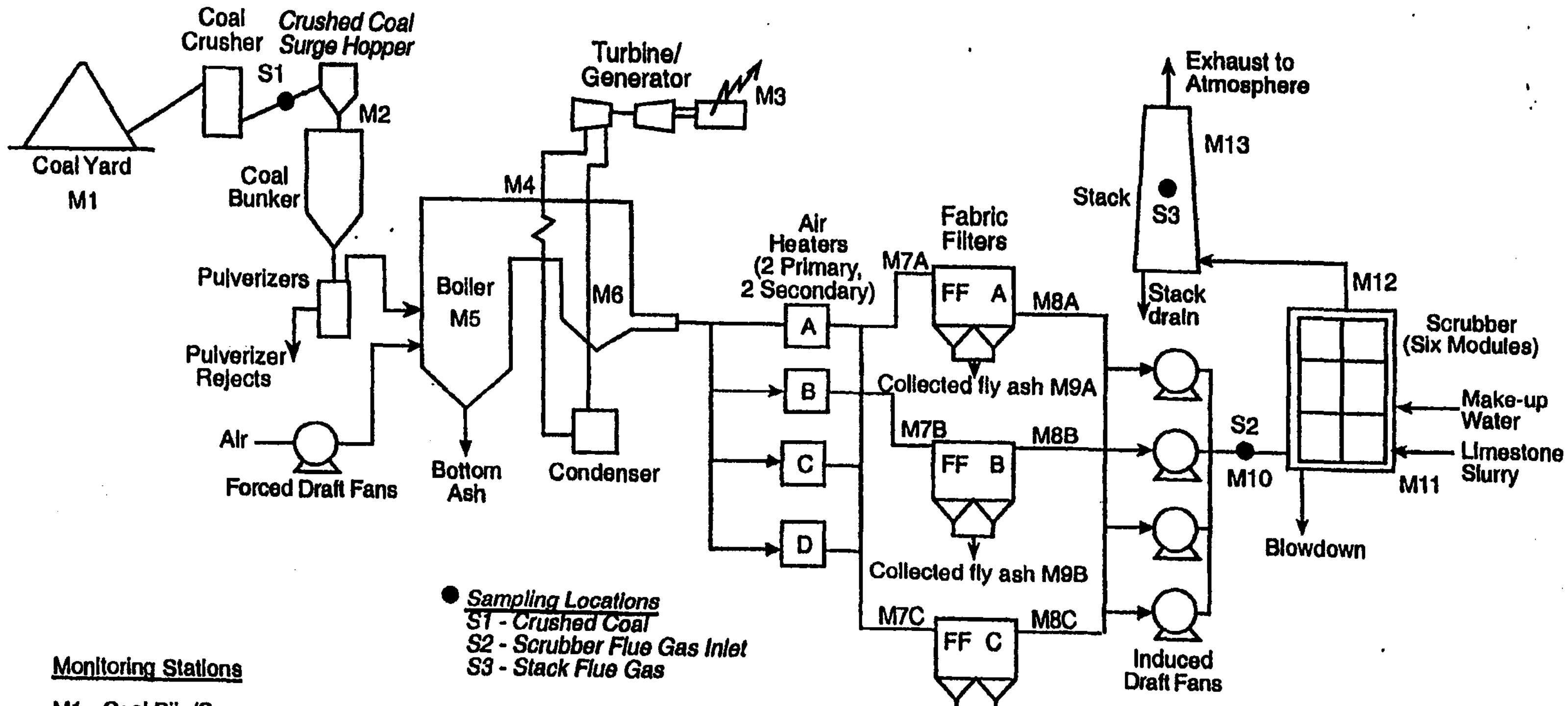
	SYSTEM DESCRIPTION	FILE NO. 9255.93.1402
	PARTICULATE REMOVAL (CCB)	IPP 082885-3



PARTICULATE REMOVAL SYSTEM
ARRANGEMENT ELEVATION
FIGURE 2-1



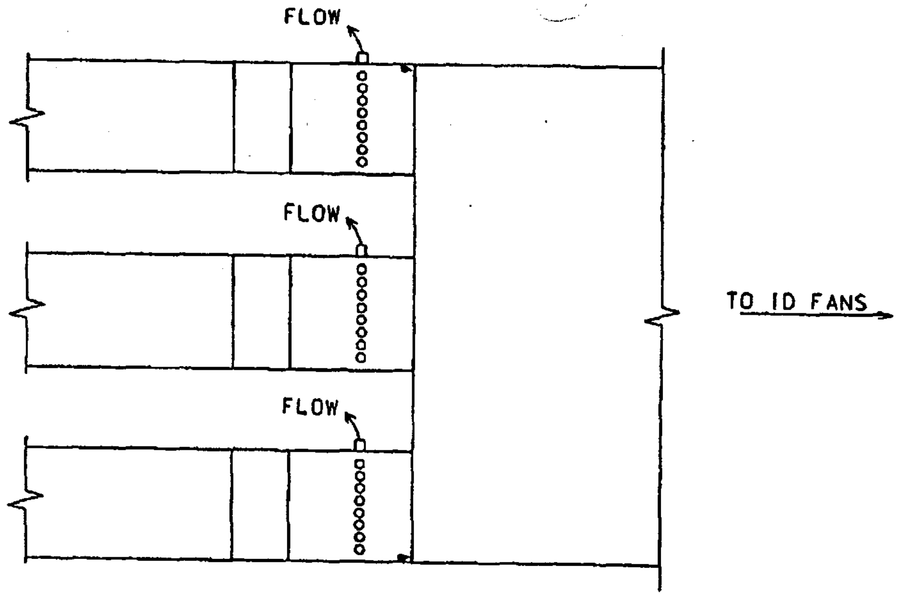
TYPICAL SCRUBBER MODULE
FIGURE 3-1



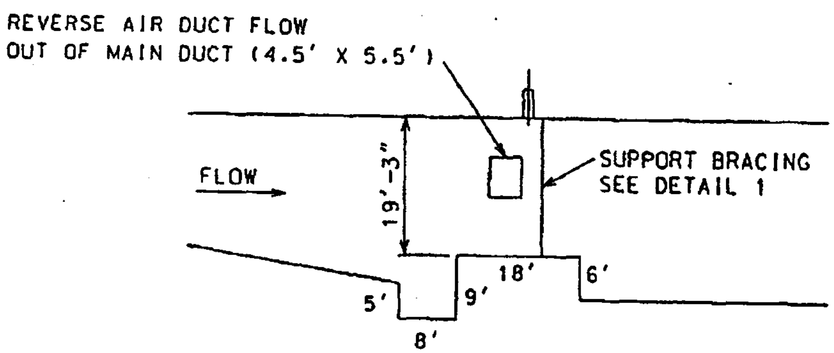
Monitoring Stations

M1 - Coal Pile/Source
M2 - Coal Feed
M3 - Generator Output
M4 - Steam Generation
M5 - Burners Firing
M6 - O2 at Convective Pass
M7 - Fabric Filter Inlets
M8 - Fabric Filter Outlets
M9 - Captured Fly Ash
M10 - Scrubber Inlet
M11- Slurry Feed Line
M12 - Scrubber Outlet
M13 - Stack

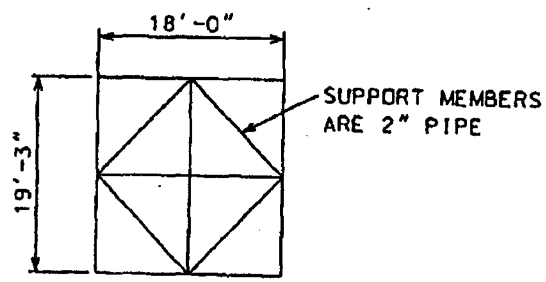
Figure 2-1. Intermountain Power Plant Boiler 2SGA process overview.



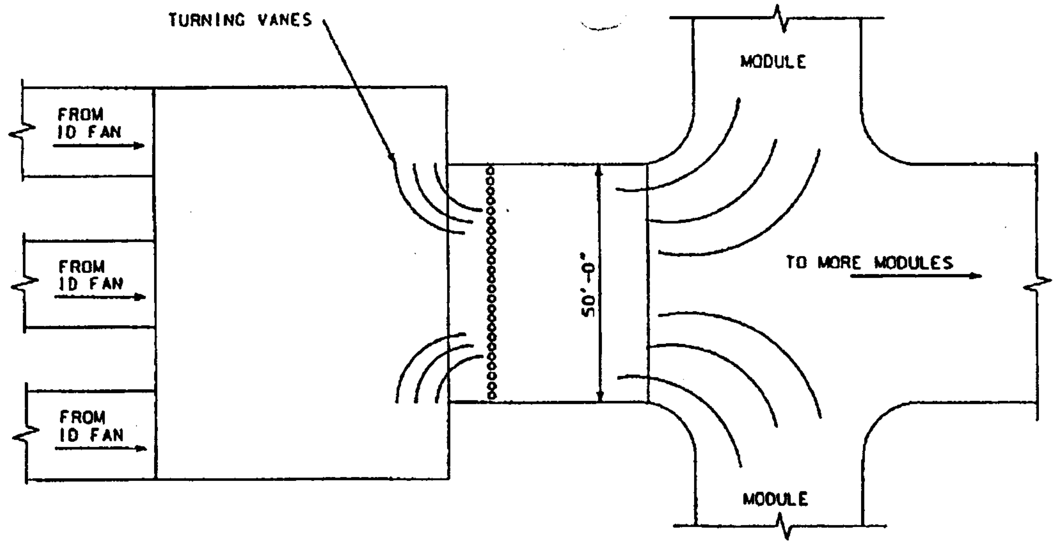
PLAN VIEW



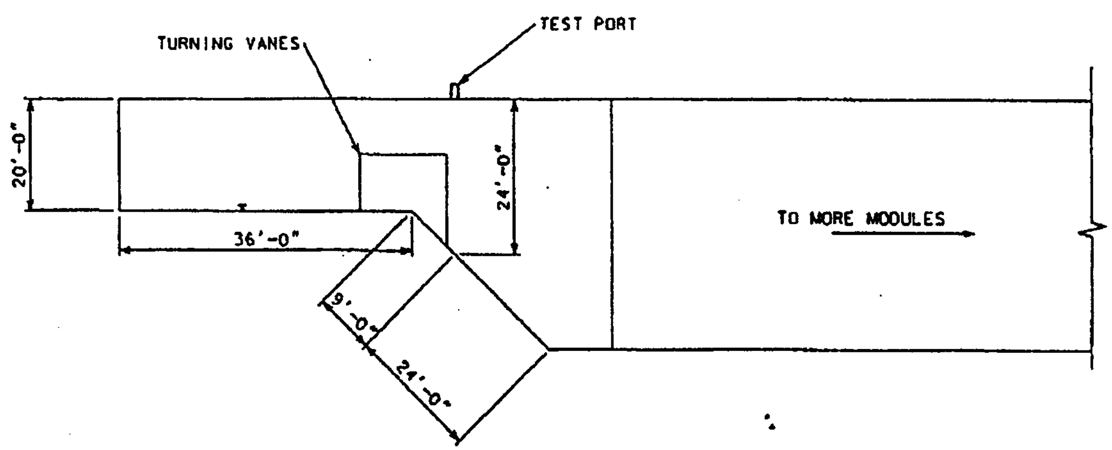
ELEVATION VIEW



DETAIL 1



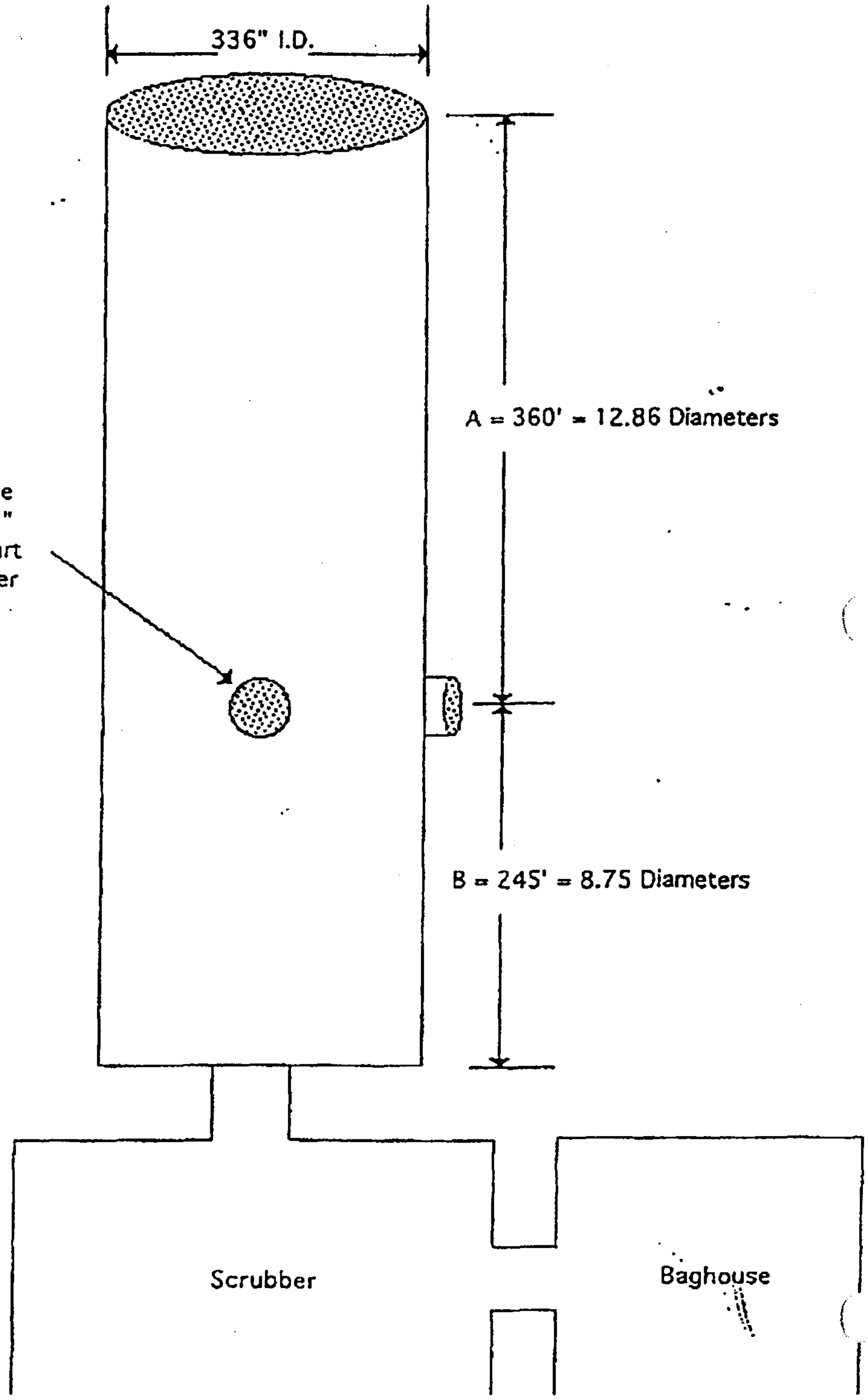
PLAN VIEW



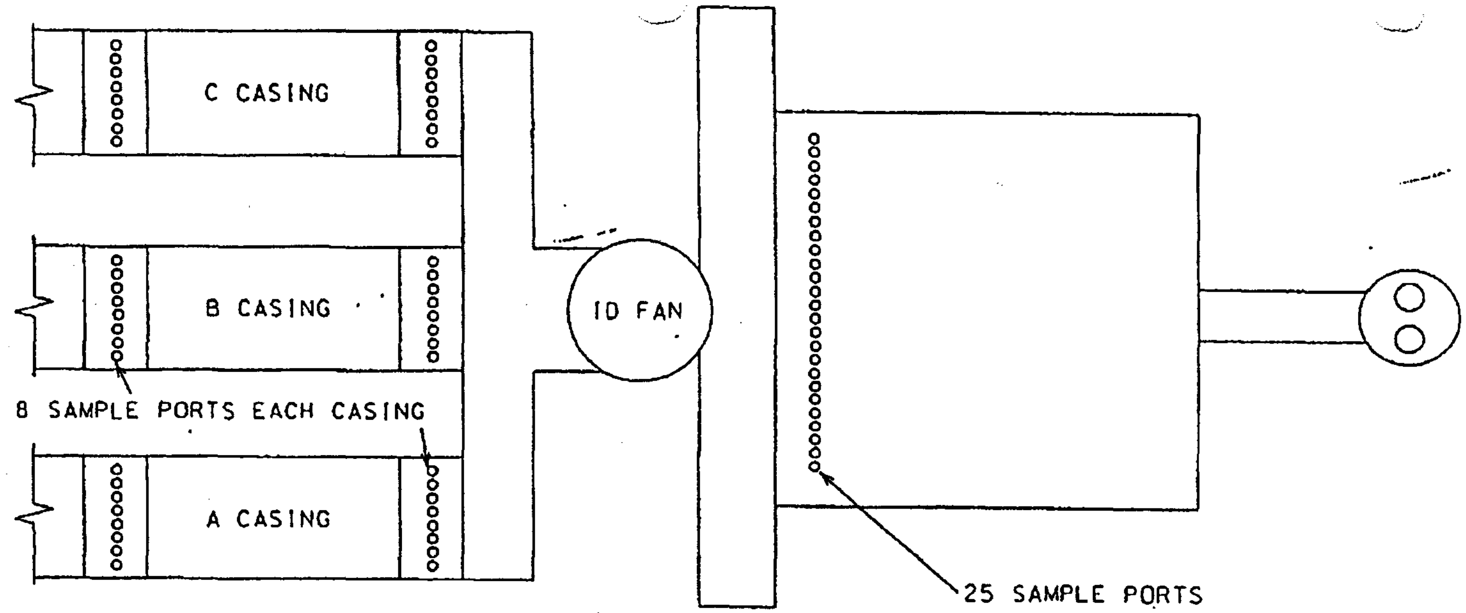
ELEVATION VIEW

Units 1 & 2 Boiler Stack Diagram

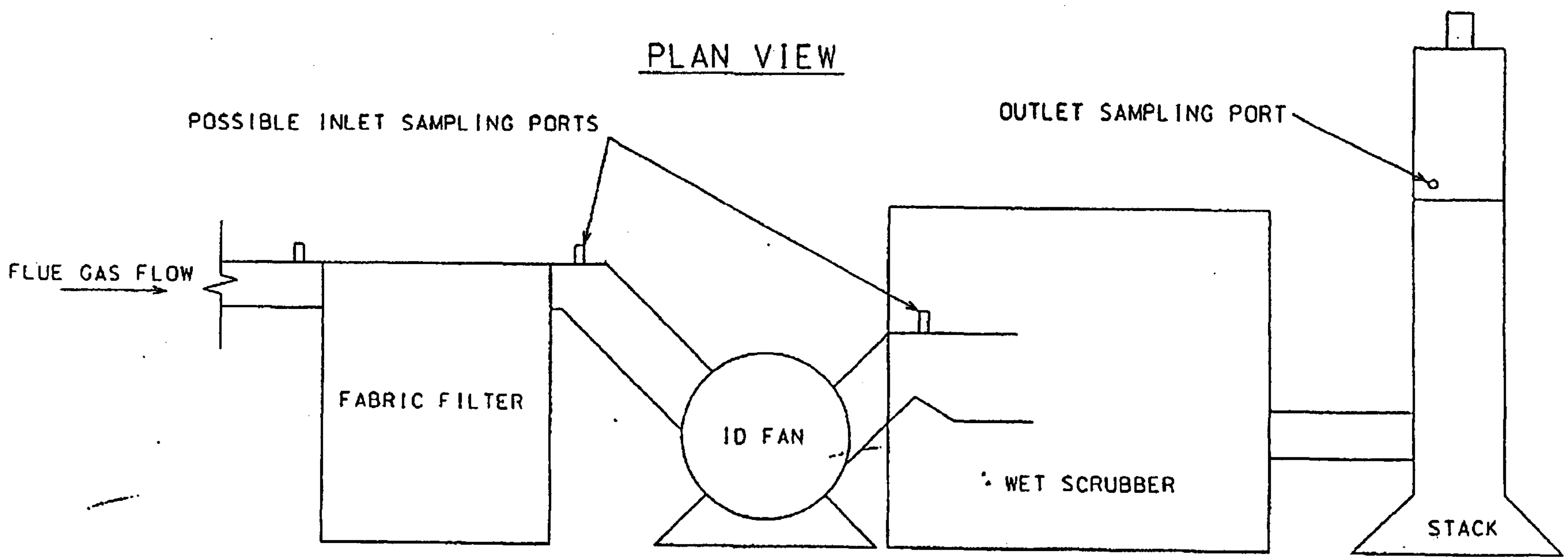
Figure II



2IP23_000226



PLAN VIEW



ELEVATION VIEW

INTERMOUNTAIN POWER SERVICE CORPORATION

June 7, 2001

Richard Sprott, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Milka Radulovic

Dear Director Sprott:

IPSC NOTICE OF INTENT: Corrections

On April 4, 2001, Intermountain Power Service Corporation (IPSC) submitted a Notice of Intent (NOI) to modify the Intermountain Generating Station (IGS) in Delta, Utah. Up through May 29, 2001, IPSC submitted other information for the NOI, including a Best Available Control Technology (BACT) analysis. Pursuant to a request from the Division of Air Quality, we are herewith submitting information that corrects inaccuracies found in those documents.

Corrections to the Notice of Intent, dated April 4, 2001:

Page 1, 2nd paragraph under Section (1) PROCESS DESCRIPTION:
This paragraph discusses boiler capacity in the last sentence. This should state that 'normal' boiler 'operating' capacity is about 6.2 million lbs steam per hour at 2822 psi drum pressure. The current boiler maximum capacity rating (MCR) is 6.6 million lbs steam per hour at 2975 psi.

Page 2, Last paragraph under Section (3) POLLUTION DEVICE DESCRIPTION:
This paragraph discusses proposed changes to NOx control technology in the last sentence. The term "moderately" should be removed, and the words "addition of best available control technology" should replace "replacement of the existing dual register low NOx burners with new technology staged combustion low NOx burners." The last sentence would then read "Also, the project includes installation of improved NOx controls, such as the addition of best available control technology."

Page 5, second bullet, "NOx Reduction Project":
The term "moderate" should be replaced with "BACT" in the first and last sentences.

ATTACHMENT 1, Worksheet A:
A new worksheet is attached to correct oversights in decimal or arithmetic errors, specific to lead and beryllium.

ATTACHMENT 1, Worksheet B:
A new worksheet is attached to correct oversights in decimal or arithmetic errors, specific to lead and beryllium.

ATTACHMENT 1, Worksheet C:
This worksheet addresses hazardous air pollutants as required at R307-410-4. There are several chemicals for which screen modeling may be required. A new worksheet is attached with modeling results using SCREEN3.

Corrections to BACT Analysis, dated May 29, 2001:

Page 2, Table 1, Typical Coal Characteristics:
This table has several different types of ASTM analytical representations of coal. To clarify this, a new Table 1 is attached here.

Completion

We appreciate the efforts of your staff in working with us. In a June 1, 2001 meeting, IPSC & DAQ discussed a probable time line to bring an approval order to fruition. We therefore assume that our NOI application is considered complete. However, IPSC will continue to provide clarifying information as requested to ensure the approval process proceeds smoothly. If, for some reason your office foresees any problem that could delay the issuance of an approval order, please contact us as soon as possible.

If you or any one of your staff have any questions, please contact Mr. Dennis Killian, Superintendent of Technical Services, at 435-864-4414, or dennis-k@ipsc.com .

Cordially,

S. Gale Chapman

S. Gale Chapman
President and Chief Operating Officer

RJC/BP/db
Enclosures

cc: Blaine Ipson, IPSC
Reed Searle, IPA
Mike Nosanov, LADWP

VIA E-MAIL FOR REVIEW — W/O SIGNATURE — M. RADULOVIC ACCEPTED AS IS — BUT WAS NEVER FORMALLY SENT.

September 5, 2001

Richard Sprott, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Milka Radulovic

Dear Director Sprott,

IPSC NOTICE OF INTENT: Uprate Modification at Intermountain

On April 4, 2001, Intermountain Power Service Corporation (IPSC) submitted a Notice of Intent (NOI) to modify the Intermountain Generating Station (IGS) in Delta, Utah. IGS will be modified to uprate capacity. IPSC has submitted additional information as requested for the NOI, including corrections, additional details, and a Best Available Control Technology (BACT) analysis. IPSC has now more clearly defined the scope of this uprate project and presents herein those modifications we intend to complete.

MODIFICATIONS AFFECTING CAPACITY

1. **High Pressure Turbine Retrofit:**
The high pressure turbine on each unit at IGS is scheduled to be replaced with a current technology, high efficiency turbine. This unit will increase high pressure turbine efficiency from approximately 84% to over 92%. Additionally, the turbine will be sized to provide up to 8.6% additional output.

2. **Cooling Tower Performance Upgrade:**
The cooling towers on each unit at IGS are scheduled for performance enhancement modifications to increase heat rejection capacity. The enhancement consists of increasing cooling fill surface area by approximately 20% by constructing a new helper cooling tower for each unit. Total circulation flow rates and cycles of concentration will not change. However, flow will be

reduced to the present towers by 20%, and redirected to the new helper towers to allow for a larger differential temperature change. To accommodate this expansion, cooling tower transformers feeding the cooling tower fan motors and new towers will be upgraded as well.

3. **Boiler Safety Valve Additions:**
Rather than add new safety valves, we have determined that we can replace one existing electro relief valve (ERV) with one main steam safety valve on each unit. This will address reliability concerns with the existing valves and accommodate the planned increase in generation capacity.

4. **Generator Cooling Enhancement:**
IPSC intends to upgrade the current generator and stator cooling systems.

5. **Isophase Bus Cooling Enhancement:**
The 26kv generator electrical bus feeding the main step-up transformer will be upgraded to enhance the current isophase bus duct cooling systems.

6. **Large Motor Bus Loading Equalization:**
We plan to equalize the loading between the large and small motor bus. Due to limited tap adjustment capability on the auxiliary transformers feeding these load centers, several motors will be moved from one supply to the other in order to maintain required motor terminal voltages as unit output is increased.

7. **Boiler Feed Pump Performance Upgrade:**
The boiler feed pump will be enhanced with improved bearing housings, flow path smoothing, and impeller clearance modifications to provide increased pump output and reliability.

8. **Main Step-up Transformer Cooling:**
The step-up transformers will be modified to increase the transformer cooling system capacity for better temperature control of the transformer oil, core, and housing.

9. **High Pressure Heater Drain Line Modifications:**
High pressure heater drain lines will be modified to eliminate resonant vibration at increased load.

10. **Boiler Modifications:**
A comprehensive study was performed by the manufacturer of the boilers (Babcock & Wilcox). This study reviewed all aspects of boiler operation at the new turbine output levels. The study also included evaluation of current technologies and operating practices for minimizing emissions, without the need to replace burners. The study recommended addition of surface area specific to primary superheat section. We intend to add 24 rows of superheat tubes across the full back-pass (convective section) of each boiler. This modification will help eliminate transient temperature anomalies and provide stable and efficient operation at the new higher rating.

11. **Circulating Water Makeup Modifications:**
A new circulating water makeup design will support increased makeup requirements and add a degree of redundancy to the system.

MODIFICATIONS AFFECTING EMISSIONS

1. **Increase Fuel Flow (Heat Input)**
In order to utilize increased capacity, coal combustion will increase approximately 5.9%.

2. **Scrubber Wall Ring:**
Patented wall rings will be installed in all twelve (12) scrubber absorber vessels to move flow back to the center of the vessel, preventing slip, and providing more efficient SO_2 and acid gas capture in the flue gas.

MODIFICATION TIME LINE

The time line for these modifications will follow the same dates as described in the Gantt chart previously submitted.

EFFECT on EMISSIONS

The emissions change for this project is calculated as follows:

Pollutant	Current Emissions (2yr Avg) tons/year	Emission Increases tons/year	Expected Emissions tons/year
PM10	787.67	9.75	797.41
SO2	3586.31	0.00	3586.31

NOx	25143.97	0.00	25143.97
CO	1317.06	77.56	1394.62
VOC	11.81	0.69	12.50
Lead	0.098	0.007	0.105
Beryllium	0.001195529	-0.00008	0.001119
Mercury	0.081	0.024	0.105
Fluorides (HF)	9.70	0.42	10.12
Sulfuric Acid	4.06	-0.11	3.96
Other HAPs (non-VOC)	59.38	0.40	59.78

We have provided no emission calculations for Hydrogen Sulfide, Total Reduced Sulfur, Reduced Sulfur Compounds, Asbestos, and Vinyl Chloride as we have no emission factors applicable to these.

We appreciate the efforts of your staff in working with us. IPSC will continue to clarify questions and issues as requested to ensure the approval process proceeds smoothly. If, for some reason your office foresees any problem that could delay the issuance of an approval order, please contact us as soon as possible.

If your or any one of you staff have any questions, please contact Mr. Dennis Killian, Superintendent of Technical Services, and 435-864-4414, or dennis-k@ipsc.com .

Cordially,

S. Gale Chapman
President and Chief Operating Officer

RJC/BP/jg

Enclosure

cc: Blaine Ipson, IPSC
Reed Searle, IPA
Mike Nosanov, LADWP

State of Utah

DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY

Michael O. Leavitt
Governor
Dianne R. Nielson, Ph.D.
Executive Director
Richard W. Sprott
Director

150 North 1950 West
P.O. Box 144820
Salt Lake City, Utah 84114-4820
(801) 536-4000 Voice
(801) 536-4099 Fax
(801) 536-4414 T.D.D.
Web: www.deq.state.ut.us

FYI

SCANNED

January 11, 2002

DAQE-049-02

S. Gale Chapman, President
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624

Dear Mr. Chapman:

Re: Approval Order: Modification to Approval Order for Increased Capacity by Modifying Units 1 & 2 and Debottlenecking, Millard County, CDS-A1, NSPS, Title V
Project Code: N0327-007

The attached document is the Approval Order (AO) for the above-referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Ms. Milka M. Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS:MR:jc

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: MODIFICATION TO APPROVAL ORDER FOR INCREASED CAPACITY BY MODIFYING UNITS 1 & 2 AND DEBOTTLENECKING

Prepared By: Milka M. Radulovic, Engineer
Email: mradulov@deq.state.ut.us
(801)536-4232

APPROVAL ORDER NUMBER

DAQE-049-02

Date: January 11, 2002

Intermountain Power Service Corporation
Source Contact
Rand Crafts
(435)864-6494

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

Abstract

Intermountain Power Service Corporation (IPSC) operates the Intermountain Generating Station (IGS) coal fired steam-electric plant, consisting of two 875 MW units, located near Delta in Millard County. IPSC is requesting a modification to their current approval order (AO) DAQE-749-01 to uprate (increase) each unit's generating capacity from 875 to 950 MW. The following are the modifications needed at the plant for the proposed uprate which will affect emissions:

1. Increase heat input through the main boilers
2. Add patented scrubber wall rings to provide more efficient SO_2 removal
3. Add more rows of tubes in the boiler super heating section

There will be other changes which will not directly affect emissions, such as:

1. Replacement of two existing high pressure turbines with two current technology and high efficiency turbines
2. Replace one existing relief valve with a safety valve on each boiler, add one new helper cooling tower (for each unit) without increasing current total circulating flow rates and cycles of concentration, boiler feed pump performance upgrade, generator and isophase cooling enhancement, and other similar changes
3. Substituting emission rate limit of 0.024 grains per dry standard cubic feet for the Group I dust collectors with an alternate limit: monthly monitoring of a differential pressure across the dust collectors.
4. In addition to the requested changes, existing emissions from the existing cooling towers were added to the plant potential to emit.

Millard County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants. New Source Performance Standards (NSPS), Subpart Da and Subpart Y apply to this source. Boiler 1 & 2 are also Group 1, Phase II units under the Acid Rain Program. IPSC is a major source of NO_x, SO_2, CO, and PM_{10}. Title V of the 1990 Clean Air Act applies to this source. The Title V permit will be administratively amended after this AO has been issued. The potential to emit, in tons per year, will change as follows: CO 98.5, VOC (HAPs and non-HAPs) 1.34, non-VOC HAPs 7.00, and other regulated pollutants 2.00.

This modification did not trigger Prevention of Significant Deterioration (PSD) regulation review since the emission increases (based on base line actual emissions and projected future emissions) were below significant levels. However, IPSC will monitor and maintain post change emissions information and submit them to the Utah Division of Air Quality on an annual basis for a period of 5 years to demonstrate that this modification did not result in a significant emissions increase. If the submitted information indicates that emissions have increased above significant levels as a consequence of the proposed change, at that time IPSC will be required to obtain a PSD permit.

The project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). A public comment period was held in accordance with UAC R307-401-4 and comments were received. The comments were evaluated and no comment was found to be adverse to the proposed AO. This air quality Approval Order (AO) authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this order.

General Conditions:

1. This Approval Order (AO) applies to the following company:

   Intermountain Power Service Corporation
   850 West Brush Wellman Road
   Delta, Utah 84624
   Phone Number: (435) 864-4414
   Fax Number: (435) 864-4970

   The equipment listed below in this AO shall be operated at the following location:

   PLANT LOCATION:

   850 West Brush Wellman Road, Delta, Millard County, Utah

   Universal Transverse Mercator (UTM) Coordinate System: datum NAD27
   4,374.4 kilometers Northing, 364.2 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307), and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. All records shall be kept for the following minimum periods:

   A. Emission inventories — Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.

   B. All other records — Five years

6. Intermountain Power Service Corporation (IPSC) shall conduct its operations of the Intermountain Generating Station (IGS) coal fired electric steam plant in accordance with the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on April 5, 2001, May 31, 2001, August 26, 2001, September 5, 2001, September 19, 2001, October 26, 2001.

7. This AO shall replace the AO (DAQE-749-01) dated September 11, 2001.

8. The approved units shall consist of the following equipment or equivalent*:

A. Unit #1 Coal Fired Boiler (Subject to NSPS, Subpart Da)
   Rating - 9,225 x 10^6 Btu/hr (MMBtu/hr)
B. Unit #2 Coal Fired Boiler (Subject to NSPS, Subpart Da)
   Rating - 9,225 MMBtu/hr
C. Coal railcar unloading dust collector 1A
D. Coal railcar unloading dust collector 1B
E. Coal railcar unloading dust collector 1C
F. Coal railcar unloading dust collector 1D
G. Coal truck unloading dust collector 2
H. Coal reserve reclaim dust collector 3
I. Coal transfer building #1 dust collector 4
J. Coal transfer building #2 dust collector 5
K. Coal transfer building #4 dust collector 6
L. Coal crusher building dust collector 11
M. U1 Generation building coal dust collector 13A
N. U1 Generation building coal dust collector 13B
O. U2 Generation building coal dust collector 14A
P. U2 Generation building coal dust collector 14B
Q. Coal pile active and reserve
R. Coal Stackout
S. Fuel oil tank 1A
   Capacity - 675,000 gallons
T. Fuel oil tank 1B
   Capacity - 675,000 gallons
U. Limestone unloading dust collector 1A
V. Limestone unloading dust collector 1B
W. Limestone transfer dust collector 1
X. Limestone reclaim dust collector 2
Y. Limestone silo bin vent filter
Z. Limestone crusher dust collector 3
AA. Limestone preparation dust collector 4
BB. Limestone storage pile
CC. Lime silo dust collector 1
DD. Lime hopper dust collector 2
EE. Soda ash silo dust collector 3
FF. Soda ash hopper dust collector 4
GG. Fly ash silo bin vent filter 1A
HH. Fly ash silo bin vent filter 1B
II. Combustion byproducts stackout & stockpile
JJ. Combustion byproducts landfill
KK. Unit 1 cooling tower 1A
LL. Unit 1 cooling tower 1B
MM. Unit 2 cooling tower 1A

NN. Unit 2 cooling tower 1B
OO. Coal sample preparation building dust collector
PP. Sandblast facility dust collector
QQ. U1 Generation building vacuum cleaning dust collector
RR. U2 Generation building vacuum cleaning dust collector
SS. U1 Fabric filter vacuum cleaning dust collector
TT. U2 Fabric filter vacuum cleaning dust collector
UU. GSB vacuum cleaning dust collector
VV. Guzzler truck dust collector
WW. Emergency diesel generators
1A, rated at - 4,000 Hp
1B, rated at - 4,000 Hp
1C, rated at - 4,000 Hp
XX. Solvent washers
YY. Diesel driven fire pump rated at 290 Hp 1B
ZZ. Diesel driven fire pump rated at 290 Hp 1C
AAA. Auxiliary boiler 1A (not subject to NSPS)
Rating - 166 MMBtu/hr
BBB. Auxiliary boiler 1B (not subject to NSPS)
Rating - 166 MMBtu/hr
CCC. Coal Conveyors
DDD. Paint booth/shops
EEE. Engine driven equipment including compressors, generators, hydraulic pumps and diesel fire pumps
FFF. Bulb recycling crusher
GGG. Laboratory fume hoods
HHH. Gasoline tank
Capacity - 500 gallons
III. Diesel tank
Capacity - 10,000 gallons
JJJ. Diesel day tanks
Capacity - not exceeding 560 gallons per tank
KKK. Mobile oil storage tanks
Capacity - not exceeding 12,000 gallons per tank
LLL. Turbine lube oil units
Capacity - not exceeding 40,000 gallons per unit
MMM. Underground storage diesel tank
Capacity - 20,000 gallons
NNN. Underground storage gasoline tank
Capacity - 6,000 gallons
OOO. Used oil tank
Capacity - 10,000 gallons
PPP. Class III Industrial Waste Landfill
QQQ. Paved haul road
RRR. Haul road and access road
SSS. Coal truck unloading grating
TTT. Two Helper cooling towers

* Equivalency shall be determined by the Executive Secretary.

Limitations and Tests Procedures

9. Emissions to the atmosphere at all times from the indicated emission points shall not exceed the following rates and concentrations:

A. **Each Main Boiler Stack**

Before the Modification (While Rated at 8,500 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	
PM_{10}	0.020*	lb/ 10^6 Btu heat input
SO_2	0.15**	lb/ 10^6 Btu heat input based on 30-day rolling-average 10.0 % of the potential combustion concentration
NO_x	0.50**	lb/ 10^6 Btu heat input based on 30-day rolling-average

After the Modification (While Rated at 9,225 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	
PM_{10}	0.0184 *	lb/ 10^6 Btu heat input
SO_2	0.138 **	lb/ 10^6 Btu heat input based on 30-day rolling-average 10.0 % of the potential combustion concentration
NO_x	0.461**	lb/ 10^6 Btu heat input based on 30-day rolling-average

B. Testing Status (To be applied above)
* Test once a year. The Executive Secretary may require testing at any time.
**Compliance for NO_x and SO_2 emissions shall be demonstrated through use of a continuous emissions monitoring system as outlined in Condition 24.

Dust Collectors

Pollutant/Source	differential pressure range across the dust collector (inches of water gage)
PM_{10}	
Rail car unloading (4 units)	0.5 to 12*
Transfer building one	0.5 to 12*
Unit one 13A	0.5 to 12*

Transfer building two	0.5 to 12*
Transfer building four	0.5 to 12*
Crusher building one	0.5 to 12*
Unit one 13B	0.5 to 12*
Unit two 14A	0.5 to 12*
Unit two 14B	0.5 to 12*
Limestone preparation building	0.5 to 12*

* If differential pressure is less than 2 inches or greater than 10 inches, work orders will be written to investigate. Dust collector may run in the 0.5 to 2 or 10 to 12 range if reason is known. Intermittent recording of the reading is required on a monthly basis. The instrument shall be calibrated against a primary standard annually. Preventive maintenance shall be done quarterly on each baghouse.

Each Auxiliary Boiler (Rated at 166 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	lbs/hr*
PM_{10}	0.10	20
SO_2	0.69	100
NO_x	0.35	58

* Testing shall be done in accordance with the requirements from the most current Title V permit.

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, and stack to be tested. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. Access that meets the standards of the Occupational Safety and Health Administration (OSHA) or the Mine Safety and Health Administration (MSHA) shall be provided.

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2

F. PM$_{10}$

For stacks in which no liquid drops are present, the following methods for informational purposes shall be used: 40 CFR 51, Appendix M, Methods 201 or 201a. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM$_{10}$.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5b, 5d, or 5e as appropriate. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM$_{10}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

G. Calculations

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

H. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

10. Visible emissions from the following emission points shall not exceed the following values:

A. All abrasive blasting - 40% opacity
B. All other points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9.

For sources that are subject to NSPS, opacity shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9.

11. The following consumption limit shall not be exceeded:

50,000 barrels of fuel oil consumed per calendar year in the auxiliary boilers.

To determine compliance with this annual limit, the owner/operator shall calculate a total by the January 20th of each year using data from the previous 12 months (ending with December 31). Records of consumption shall be kept for all periods when the auxiliary boilers are in operation. Consumption shall be determined by fuel oil totalizer records. The records of consumption shall be kept on a monthly basis.

12. Annual emissions from the entire plant shall not exceed the following amounts:

    CO ..... 1989.60* tons per rolling 12-month period

    * Emission factors for CO shall be derived from the most recent EPA's Compilation of Air Pollutant Emission Factors (AP-42), industry specific published emission factors (such as Electric Power Research Institute, Edison Electric Institute), fuel analysis, and IPSC own testing as appropriate.

13. Emergency generators shall be used for electricity producing operation only during the periods when regular electric power supply is interrupted, except for routine engine maintenance and testing. Records documenting generator usage shall be kept in a log and shall show the date the generator was used, the duration in hours of generator usage, and the reason for each usage.

14. The diesel driven fire pumps shall be operated on an emergency basis only, except for routine engine and fire system maintenance and testing. Records documenting diesel driven fire pump usage shall be kept in a log and shall show the date the diesel driven fire pump was used, the duration in hours of use, and the reason for each usage.

Roads and Fugitive Dust

15. IPSC shall abide by the latest fugitive dust control plan submitted to the Executive Secretary for control of all dust sources associated with the Intermountain Power Generation site.

    Any haul road speeds established in the plan shall be posted.

16. The facility shall abide by all applicable requirements of R307-205 for Fugitive Emission and Fugitive Dust sources.

Fuels

17. The owner/operator shall combust only bituminous and subbituminous coals as primary fuels and shall only use diesel oil or natural gas during the startups, shutdowns, maintenance, performance tests, upsets and for flame stabilization in the 8,500 x 10^6 and 9,225 x 10^6 Btu/hr boilers. Only No. 2 oil shall be used in 166 x 10^6 Btu/hr boilers. The owner/operator may fuel-blend self-generated used oil with coal at the active coal pile reclaim structure providing that self-generated used oil has not been mixed with hazardous waste.

18. The sulfur content of any fuel oil combusted shall not exceed:

    A. 0.85 lb per x 10^6 Btu heat input for fuel oil used in the main boilers.
    B. 0.58 percent by weight for fuel oil combusted in the auxiliary boilers.

    The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall either be by IPSC's own testing or test reports from the fuel oil marketer.

Federal Limitations and Requirements

19. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18 and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) and Subpart Y, 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants) apply to this installation.

20. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 - Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Records & Miscellaneous

21. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded, and the records shall be maintained for a period of two years.

22. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

23. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

Monitoring - Continuous Emissions Monitoring

24. The owner/operator shall install, calibrate, maintain, and continuously operate a continuous emissions monitoring system (CEMs) on the main boilers stacks and SO_2 removal scrubbers inlets. The owner/operator shall record the output of the system, for measuring the opacity, SO_2, NO_x, CO_2 emissions. The monitoring system shall comply with all applicable sections of R307-170, UAC; and 40 CFR 60, Appendix B.

    All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

    Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring devices and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section UAC R307-170.

25. In order to demonstrate that the modification did not result in significant emissions increases (as defined in R307-101-2), the rolling 12-month period (that is compiled quarterly) main boilers 1&2 fuel consumption data (MMBtu/hr) and emissions from their stack flues shall be monitored for at least 5 years from the date the units begin fully using the modifications described herein as regular operation. If IPSC fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased above the significant emission increases as a consequence of the change, IPSC will be required to obtain a PSD permit for these modifications at that time. Records of NO_x and SO_2 shall be obtained through the use of a CEM. Records of PM_{10} shall be based on annual stack tests outlined in the Condition 9. Records for the rest of pollutants shall be based on the EPA's Compilation of Air Pollutant Emission Factors (AP-42), industry specific published emission factors (such as Electric Power Research Institute, Edison Electric Institute or IPSC own testing).

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.eq.state.ut.us/eqair/aq_home.htm

The annual emission estimations below include point source, fugitive emissions, fugitive dust and do not include road dust, tail pipe emissions, grandfathered emissions etc. These emissions are for the purpose of determining the applicability of Prevention of Significant Deterioration, nonattainment area, maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential To Emit (PTE) emissions for the IPSC power generation plant are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10}	3,286.70
B.	SO_2	11,332.30
C.	NO_x	37,868.20
D.	CO	1,989.6
E.	VOC	63.91
F.	HAPs	82.67
	Lead	0.39168
	Beryllium	0.00892
	Mercury	0.3135
	Fluorides (HF)	16.80
	Sulfuric Acid	8.80
	Other non-VOC HAPs	93.20

Approved By:

Richard W. Sprott, Executive Secretary
Utah Air Quality Board